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# **Energy Requirements for Controlling SO<sub>2</sub> Emissions from Coal-Fired Steam/Electric Generators**

**Radian Corp, Austin, Tex**

**Prepared for**

**Environmental Protection Agency, Research Triangle Park, N C**

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**December 1977**

**ENERGY REQUIREMENTS  
FOR CONTROLLING  
SO<sub>2</sub> EMISSIONS  
FROM COAL-FIRED  
STEAM/ELECTRIC  
GENERATORS**



**U.S. ENVIRONMENTAL PROTECTION AGENCY  
Office of Air and Waste Management  
Office of Air Quality Planning and Standards  
Research Triangle Park, North Carolina 27711**

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FROM COAL-FIRED  
STEAM/ELECTRIC GENERATORS**

by

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## LIST OF ABBREVIATIONS

|                 |                                                 |
|-----------------|-------------------------------------------------|
| acf             | -- actual cubic foot                            |
| Btu             | -- British thermal unit                         |
| cf              | -- cubic foot                                   |
| D-A             | -- double-alkali FGD                            |
| EPA             | -- Environmental Protection Agency              |
| exp             | -- exponent                                     |
| °F              | -- degree Fahrenheit                            |
| FD              | -- forced draft                                 |
| FGD             | -- flue gas desulfurization                     |
| g               | -- gram                                         |
| gal             | -- gallon                                       |
| GJ              | -- gigajoule                                    |
| HP              | -- horsepower                                   |
| hr              | -- hour                                         |
| ID              | -- induced draft                                |
| J               | -- joule                                        |
| °K              | -- degree Kelvin                                |
| kg              | -- kilogram                                     |
| kJ              | -- kilojoule                                    |
| km              | -- kilometer                                    |
| kW              | -- kilowatt                                     |
| L               | -- lime FGD                                     |
| LS              | -- limestone FGD                                |
| m <sup>3</sup>  | -- cubic meter                                  |
| MAF             | -- moisture ash free                            |
| MgO             | -- magnesium oxide FGD                          |
| MJ              | -- megajoule                                    |
| MW              | -- megawatt                                     |
| Nm <sup>3</sup> | -- normal cubic meter                           |
| NSPS            | -- New Source Performance Standard              |
| OAQPS           | -- Office of Air Quality Planning and Standards |

# ABBREVIATIONS (Cont'd)

|       |                                 |
|-------|---------------------------------|
| ROM   | -- run-of-mine                  |
| rem   | -- removed                      |
| s     | -- second                       |
| scf   | -- standard cubic foot          |
| scfh  | -- standard cubic foot per hour |
| stm   | -- steam                        |
| TVA   | -- Tennessee Valley Authority   |
| W-L/A | -- Wellman-Lord/Allied FGD      |
| yr    | -- year                         |

# METRIC CONVERSION FACTORS

| <u>To Convert From</u>        | <u>To</u>                     | <u>Multiply by</u>    |
|-------------------------------|-------------------------------|-----------------------|
| British thermal unit (Btu)    | joule (J)                     | 1055                  |
| degree Fahrenheit (°F)        | degree Kelvin (°K)            | $K = (F + 460) / 1.8$ |
| cubic foot (ft <sup>3</sup> ) | cubic meter (m <sup>3</sup> ) | 0.02832               |
| gallon (gal)                  | cubic meter (m <sup>3</sup> ) | 0.003785              |
| horsepower (HP)               | watt (W)                      | 746.0                 |
| hour (hr)                     | second (s)                    | 3600                  |
| inch (in) of H <sub>2</sub> O | pascal (Pa)                   | 249.1                 |
| mile (mi)                     | meter (m)                     | 1609                  |
| pound (lb)                    | gram (g)                      | 453.6                 |

## Multiplication Factors

## Symbol

10<sup>3</sup>

k

10<sup>6</sup>

M

10<sup>9</sup>

G

## 1.0

### INTRODUCTION

This report summarizes work done by Radian Corporation for EPA under Contract 68-02-2608, task 8. It describes the energy penalties associated with the control of SO<sub>2</sub> emissions from coal-fired power plants.

## 1.1

### Background

The existing New Source Performance Standard (NSPS) for SO<sub>2</sub> emissions from coal-fired steam generators is 0.52 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input. Depending on coal sulfur content and heating value, compliance with this standard can be achieved by means of flue gas desulfurization (FGD), coal desulfurization, the use of low sulfur coal, or a combination of these approaches. Since the promulgation of the SO<sub>2</sub> NSPS in 1971, advances have been made in the performance and reliability of FGD processes. Because of these advances, public interest groups have requested that the EPA promulgate more stringent SO<sub>2</sub> emission standards. Therefore, the EPA's Office of Air Quality Planning and Standards (OAQPS) has undertaken a program to review the existing NSPS. The results of this program will be used to determine whether the NSPS should be revised.

This report is provided by Radian Corporation to assist OAQPS in the review of the NSPS. It addresses the energy penalties which result from employing various control methods to reduce SO<sub>2</sub> emissions to certain specified levels. In addition, it compares energy requirements for SO<sub>2</sub> control to projected total U.S. energy consumption in 1987 and 1997.

## 1.2 Approach

The study approach was based on an EPA model including 102 systems which are combinations of power plants and SO<sub>2</sub> control methods. The variables considered in the model are level of SO<sub>2</sub> control, method of SO<sub>2</sub> control, power plant size, and coal composition. The levels of each variable considered in this study and the combinations of variables were defined by EPA as shown in Table 1-1. Three levels of SO<sub>2</sub> control were considered. They include the existing NSPS (0.52 g SO<sub>2</sub>/MJ heat input), 90 percent SO<sub>2</sub> removal, and 0.22 g SO<sub>2</sub>/MJ. Control methods considered include regenerable FGD processes, nonregenerable FGD processes, transportation of low sulfur coal to the Midwest, and a combination of coal cleaning and nonregenerable FGD processes.

Base case energy requirements for each SO<sub>2</sub> control method were calculated from material and energy balances. The base case was 90 percent SO<sub>2</sub> removal from the flue gas of a 500 MW power plant burning 3.5 percent sulfur coal. Extrapolation factors which describe energy requirements in terms of flue gas rate and SO<sub>2</sub> removal were defined. The extrapolation factors were used to calculate energy requirements for all the power plant/SO<sub>2</sub> control system combinations included in the model.

## 1.3 Summary of Results

The results show how energy penalties depend on control method, level of control, and coal composition. It was found that per kW of generating capacity, plant size had little effect on energy penalties.

TABLE 1-1. MODEL SO<sub>2</sub> EMISSION CONTROL SYSTEMS STUDIED

| SO <sub>2</sub> Control Level                                            | Plant Sizes Considered, MW | FGD Processes Considered* | Coal                                                                      |
|--------------------------------------------------------------------------|----------------------------|---------------------------|---------------------------------------------------------------------------|
| 0.52 g SO <sub>2</sub> /MJ (1.2 lb SO <sub>2</sub> /10 <sup>6</sup> Btu) | 25, 100, 500, 1000         | LS, L, MgO, W-L/A, D-A    | 3.5% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500, 1000         | LS, L                     | 7.0% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 500                    | ---                       | 0.6% sulfur; 20.9 MJ/kg western coal transported to a Midwest power plant |
|                                                                          | 25, 500                    | ---                       | 0.8% sulfur; 25.6 MJ/kg western coal transported to a Midwest power plant |
|                                                                          | 500                        | LS, L                     | 2.3% sulfur; 29.2 MJ/kg**                                                 |
| 90% SO <sub>2</sub> Removal by FGD                                       | 25, 100, 500, 1000         | LS, L, MgO, W-L/A, D-A    | 3.5% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500, 1000         | LS, L, MgO, W-L/A, D-A    | 7.0% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500               | LS, L                     | 0.8% sulfur; 20.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500               | LS, L                     | 0.8% sulfur; 25.6 MJ/kg                                                   |
| 0.22 g SO <sub>2</sub> /MJ (0.5 lb SO <sub>2</sub> /10 <sup>6</sup> Btu) | 25, 500                    | LS, L                     | 0.8% sulfur; 20.9 MJ/kg                                                   |
|                                                                          | 25, 500                    | LS, L                     | 0.8% sulfur; 25.6 MJ/kg                                                   |
|                                                                          | 25, 500                    | LS, L                     | 2.3% sulfur; 29.2 MJ/kg**                                                 |
|                                                                          | 25, 500                    | LS, L                     | 4.6% sulfur; 29.2 MJ/kg***                                                |

\*LS = Limestone

L = Lime

MgO = Magnesia Slurry

W-L/A = Wellman-Lord/Allied

D-A = Double-Alkali

\*\*Physically cleaned 3.5% sulfur; 27.9 MJ/kg coal (40% sulfur removal)

\*\*\*Physically cleaned 7.0% sulfur; 27.9 MJ/kg coal (40% sulfur removal)

Table 1-2 shows the energy penalties associated with different methods of control of SO<sub>2</sub> emissions. Energy penalties are described in terms of percent of energy input to an equivalent capacity uncontrolled power plant. A range of energy penalties is given. The variations are due to percent sulfur in the coal, level of SO<sub>2</sub> control and, to a small extent, plant size. For the FGD processes, the high end of these ranges represents the most difficult control cases--combustion of 7 percent sulfur coal with 90 percent SO<sub>2</sub> removal.

Table 1-2 shows that the lowest energy penalties are associated with nonregenerable FGD processes.

TABLE 1-2. ENERGY PENALTIES ASSOCIATED WITH DIFFERENT METHODS OF CONTROLLING SO<sub>2</sub> EMISSIONS

| SO <sub>2</sub> Control Method                                   | Energy Penalty<br>(% Energy Input to Equivalent<br>Uncontrolled Power Plant) |
|------------------------------------------------------------------|------------------------------------------------------------------------------|
| Nonregenerable FGD processes<br>(Lime, Limestone, Double-Alkali) | 3.0 - 4.5                                                                    |
| Regenerable Magnesia Slurry<br>FGD process                       | 5.0 - 10.0                                                                   |
| Transportation of low Sulfur coal                                | 5.5 - 6.5                                                                    |
| Coal cleaning plus nonregenerable<br>FGD process                 | 10.0 - 11.0                                                                  |
| Regenerable Wellman-Lord/Allied<br>(W-L/A) FGD process           | 12.0 - 25.0                                                                  |

Figure 1-1 shows how energy penalties depend on the level of SO<sub>2</sub> control. Two levels of control are shown, the existing standard and 90 percent SO<sub>2</sub> removal. Ninety percent removal is a more stringent level of control than the existing standard. Figure 1-1 shows that for most control methods the energy penalty for achieving 90 percent removal is about 10-15 percent higher than that required to meet the existing NSPS.

The results of the study also show that for combustion of low sulfur western coal, 90 percent SO<sub>2</sub> removal requires up to 10 percent more energy than controlling emissions to 0.22 g SO<sub>2</sub>/MJ (0.5 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input. For low sulfur coals, 0.22 g SO<sub>2</sub>/MJ is more stringent than the existing NSPS but less stringent than 90 percent removal.

For a "bare bones" SO<sub>2</sub> control system, the energy required for flue gas reheat and particulate/chloride removal is excluded from the limestone and lime systems. This reduces the energy requirements of these systems by 50 to 60 percent. For the double-alkali, magnesia slurry and Wellman-Lord/Allied processes, the particulate/chloride removal operation is required to prevent buildup of chlorides in the SO<sub>2</sub> scrubbing liquor. However, excluding flue gas reheat requirements would reduce the energy required by the MgO system by 15 to 25 percent, the W-L/A by about 10 percent and the double-alkali by about 50 percent.

The energy penalties associated with SO<sub>2</sub> controls were compared with projected total U.S. energy consumption for 1987 and 1997. Depending on control level, method of control, and sulfur content of coal, the energy required to control SO<sub>2</sub> emissions from new coal-fired power plants will be from 0.5 to 4.4 percent of total energy consumption in 1987. In 1997 the energy penalty ranges from 0.7 to 6.3 percent of projected consumption. Assuming the majority of future SO<sub>2</sub> controls are limestone or lime

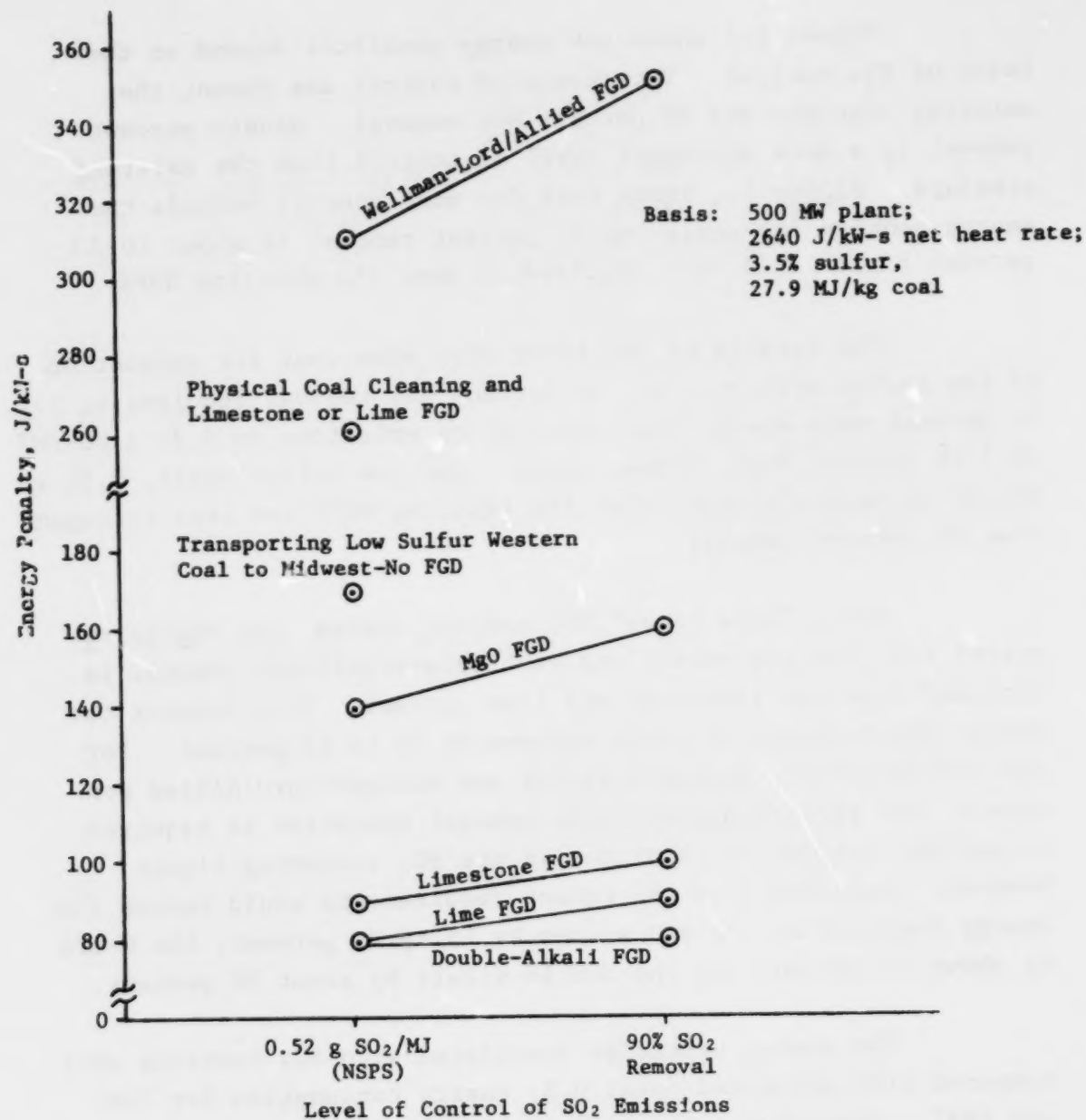


Figure 1-1. Energy penalties for SO<sub>2</sub> control - summary of effects of SO<sub>2</sub> control level.

FGD systems, as is presently true, the ranges for 1987 and 1997 would be 0.5 to 0.7 percent and 0.7 to 1.0 percent, respectively.

The objectives of this study were to identify and compare the energy impacts of various levels and means of controlling SO<sub>2</sub> emissions from coal-fired power plants. These objectives were achieved by developing energy requirement data for 102 model power plant/SO<sub>2</sub> emission control systems selected by the EPA. The designs used in this study are believed to be representative of those available to industry. It should be noted that in industry the design of a power plant/SO<sub>2</sub> emission control system is based on economic considerations. Site specific economic considerations therefore will have an influence on the data developed in this study. However, it is believed that the general conclusions resulting from this study are valid for the majority of economic situations encountered in industry.

Four major variables--plant capacity, coal sulfur content, level of SO<sub>2</sub> control and means of SO<sub>2</sub> control--were examined to determine their effect on the energy required to control SO<sub>2</sub> emissions from coal-fired power plants. The results of the study indicate that per unit of generating capacity, power plant size has little influence on the energy penalties associated with SO<sub>2</sub> emission controls. The effects of the other three variables are discussed below.

- 1) For combustion of a 3.5 percent sulfur coal and use of an FGD process, the energy requirements for achieving 90 percent SO<sub>2</sub> removal are 10-15 percent greater than for complying with the existing new source performance standard of 0.52 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input. For coal sulfur contents greater than 3.5 percent, the difference

in energy penalties for the two control levels decreases. This is because as coal sulfur content increases, the percent SO<sub>2</sub> removal required to comply with the existing NSPS also increases, reaching 90 percent removal for a coal sulfur content of about 7 percent.

- 2) From an energy viewpoint, the nonregenerable FGD processes--limestone, lime, and double-alkali--are the best means of controlling SO<sub>2</sub> emissions from coal-fired power plants. The range of energy requirements, as a percent of the energy input to an equivalent uncontrolled power plant, for the SO<sub>2</sub> control methods examined are:

Nonregenerable FGD processes - 3.0 - 4.5%

Regenerable FGD processes

magnesia slurry - 5 - 10%

Wellman-Lord/Allied - 12 - 25%

Physical coal cleaning and use

of limestone or lime FGD - 10 - 11%

Transporting low sulfur

western coal to the Midwest;

no FGD - 5.5 - 6.5%

Variations are due mainly to percent sulfur in the coal, level of SO<sub>2</sub> control and to a lesser extent plant size.

### 3.0

#### DESIGN ASSUMPTIONS

The EPA selected 102 model power plant/SO<sub>2</sub> emission control systems for examination in this study. These model systems were based on combinations of the following variables:

- 1) Level of Control of SO<sub>2</sub> emissions
  - 0.52 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input (the existing SO<sub>2</sub> NSPS)
  - 90 percent SO<sub>2</sub> removal by FGD
  - 0.22 g SO<sub>2</sub>/MJ (0.5 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input
- 2) The means of controlling SO<sub>2</sub> emissions
  - Limestone slurry scrubbing
  - Lime slurry scrubbing
  - Magnesia slurry scrubbing
  - Wellman-Lord/Allied sodium solution scrubbing
  - Double-alkali scrubbing
  - Physical coal cleaning
  - Use of low sulfur western coal in a Midwest power plant

Other variables were power plant capacity and coal composition. Four power plant capacities and five run-of-mine coals were considered. The design assumptions used in this study for the model system power plants and SO<sub>2</sub> control methods are discussed in Sections 3.1 and 3.2, respectively.

### 3.1

#### Power Plant Design and Operating Assumptions

Two high sulfur eastern coals and three low sulfur western coals were used as boiler fuels. In addition, for several of the model control systems the two eastern coals

were physically cleaned (40 percent sulfur removal) prior to combustion. The compositions and heating values of these seven coals are listed in Table 3-1. Combustion calculations were performed for the first six coals listed in Table 3-1. (See Table 3-2.) These flue gas compositions served as the bases for estimating the energy requirements for the FGD processes. A combustion calculation was not performed for the last coal in Table 3-1 since the model power plant/SO<sub>2</sub> control systems which used this coal did not require an FGD process for SO<sub>2</sub> control.

The power plant capacities examined in this study are assumed to be net capacities, i.e., the capacity available after providing for plant auxiliaries. FGD processes also require auxiliary energy in the form of steam and electricity. If this energy is obtained from the power plant, the net generating capacity of the plant will be lowered. In the past, power plants have generally been designed with fairly standardized net capacities. If these same standardized net capacities are desired, allowances for the energy requirements of the FGD system must be made in the design of the plants. This should not pose any unusual design problems, but will increase the cost of the power plant (CO-644).

### 3.2 Emission Control System Design Assumptions

The design options for the SO<sub>2</sub> emission control techniques selected for examination are representative of those that are commercially available. In actual practice, it might be advantageous to make changes in design options as the emission control parameters change. However, for this study the same design bases are used for all of the model SO<sub>2</sub> emission control systems. The design bases and assumptions used for the FGD and

TABLE 3-1. COMPOSITIONS AND HEATING VALUES OF THE MODEL SYSTEM BOILER FUELS

| Coal Designation                                  | wt % Sulfur |           |  | wt % H <sub>2</sub> O | wt % Ash | Heating Value, MJ/kg<br>(Btu/lb) |
|---------------------------------------------------|-------------|-----------|--|-----------------------|----------|----------------------------------|
|                                                   | Dry Basis   | Wet Basis |  |                       |          |                                  |
| Eastern Coal - 3.5% Sulfur                        | 3.5         | 3.3       |  | 5.7                   | 12       | 27.9 (12,000)                    |
| Eastern Coal - 7.0% Sulfur                        | 7.0         | 6.6       |  | 5.7                   | 12       | 27.9 (12,000)                    |
| Physically Cleaned<br>3.5% Sulfur Eastern Coal    | 2.3         | 2.2       |  | 6.3                   | 6.6      | 29.2 (12,500)                    |
| Physically Cleaned<br>7.0% Sulfur Eastern Coal    | 4.6         | 4.4       |  | 6.3                   | 6.6      | 29.2 (12,500)                    |
| Western Coal - 0.8% Sulfur,<br>Low Heating Value  | 0.8         | 0.7       |  | 13.2                  | 23       | 20.9 ( 9,000)                    |
| Western Coal - 0.8% Sulfur,<br>High Heating Value | 0.8         | 0.7       |  | 10                    | 10       | 25.6 (11,000)                    |
| Western Coal - 0.6% Sulfur,<br>Low Heating Value  | 0.6         | 0.5       |  | 13.2                  | 23       | 20.9 ( 9,000)                    |

TABLE 3-2. COMBUSTION CALCULATION ASSUMPTIONS AND RESULTS

| Coal<br>Designation               | 3.5% Sulfur |  | 7.0% Sulfur |  | Physically Cleaned<br>3.5% Sulfur |  | Physically Cleaned<br>7.0% Sulfur |  | 0.8% Sulfur,<br>Low Heating<br>Value Western |  | 0.8% Sulfur,<br>High Heating<br>Value Western |  |
|-----------------------------------|-------------|--|-------------|--|-----------------------------------|--|-----------------------------------|--|----------------------------------------------|--|-----------------------------------------------|--|
|                                   | Eastern     |  | Eastern     |  | Eastern                           |  | Eastern                           |  | Low Heating<br>Value Western                 |  | High Heating<br>Value Western                 |  |
| Flue Gas<br>Composition,<br>Vol % |             |  |             |  |                                   |  |                                   |  |                                              |  |                                               |  |
| N <sub>2</sub>                    | 74.61       |  | 74.45       |  | 74.67                             |  | 74.56                             |  | 74.48                                        |  | 74.49                                         |  |
| CO <sub>2</sub>                   | 12.55       |  | 12.52       |  | 12.56                             |  | 12.54                             |  | 12.81                                        |  | 12.81                                         |  |
| O <sub>2</sub>                    | 4.86        |  | 4.85        |  | 4.86                              |  | 4.86                              |  | 4.88                                         |  | 4.88                                          |  |
| H <sub>2</sub> O                  | 7.76        |  | 7.74        |  | 7.76                              |  | 7.75                              |  | 7.77                                         |  | 7.77                                          |  |
| SO <sub>2</sub>                   | 0.22        |  | 0.44        |  | 0.15                              |  | 0.29                              |  | 0.06                                         |  | 0.05                                          |  |

Assumptions

- Horizontal, frontal-fired boilers
- 20% excess air to boiler
- 13% additional excess air as leakage in air preheater
- 92% of sulfur evolves as SO<sub>2</sub>
- Temperature of flue gas exiting preheaters is 428°K (310°F)

coal cleaning processes and for transporting western coal to the Midwest are discussed in the following sections.

### 3.2.1 Design Assumptions for FGD Process

There are six basic process operations in the limestone, lime, MgO, Wellman-Lord/Allied and double-alkali FGD processes:

- Raw material handling and feed preparation,
- Particulate/chloride removal,
- SO<sub>2</sub> scrubbing,
- Reheat,
- Fans, and
- Sulfur disposal/recovery.

The raw material handling and feed preparation operation is designed to receive, store and prepare makeup reagents for the FGD processes. This requires storage silos, conveyors, grinders, mixers, slurry or solution preparation tanks and pumps. The lime and double-alkali processes use lime as the SO<sub>2</sub> sorbent or precipitation reagent. Facilities for calcining limestone to produce the lime were not included in the design basis. If these facilities were included, the energy requirements of the raw material handling and feed preparation operations would be increased by about a factor of 50 (EN-587). This in turn would increase the energy requirements of the lime and double-alkali processes by about 25 percent.

The energy required to extract, process and transport the raw materials for the FGD processes were not included in this study. To examine this aspect of the FGD system energy requirements would require defining the location of specific

power plants and raw material producers, and is outside the scope of this study.

The design bases selected for the other processing steps are summarized in Table 3-3. The following sections briefly discuss these selections.

#### Particulate/Chloride Removal

In the magnesium oxide, Wellman-Lord/Allied and double-alkali FGD processes, particulates and chlorides must be removed from the flue gas prior to the SO<sub>2</sub> scrubbers. This is required because the SO<sub>2</sub> scrubbing liquors in these systems are regenerated and recycled. If chlorides and particulates are removed along with the SO<sub>2</sub>, they will build up in the scrubbing liquor and cause operational problems such as corrosion of equipment. Although particulates can be removed by baghouse filters or electrostatic precipitators, chloride removal requires a wet scrubbing device. For this study, venturi scrubbers were selected for chloride removal. The removal of particulates along with the chlorides imposes no additional energy requirements.

In the limestone and lime processes, it is feasible to remove particulates, chlorides and SO<sub>2</sub> simultaneously because the particulates and chlorides will be purged from the scrubbing liquor with the calcium sulfite/sulfate solids. However, this will result in increased levels of solids and chlorides in the recirculating scrubbing liquor. This in turn may cause operational problems and/or not be the optimum operating mode. For example, chlorides in the scrubbing liquor reduce the alkalinity available to sorb SO<sub>2</sub>. As the available alkalinity decreases, the scrubbing liquor recirculation rate must be increased, increasing the power requirements for the SO<sub>2</sub> removal operation. A higher level of chlorides in the recirculating liquor may also

TABLE 3-3. PROCESS DESIGN BASES FOR FGD PROCESSES\*

| Process Step                 | FGD Process             |                         |                             |                                |
|------------------------------|-------------------------|-------------------------|-----------------------------|--------------------------------|
|                              | Limestone               | Lime                    | HgO                         | Wellman-Lord/Allied            |
| Particulate/Chloride Removal | Venturi                 | Venturi                 | Venturi                     | Venturi                        |
| SO <sub>2</sub> Scrubbing    | Mobile Bed              | Mobile Bed              | Venturi                     | Mobile Bed                     |
| Reheat                       | Indirect Steam Reheater | Indirect Steam Reheater | Indirect Steam Reheater     | Indirect Steam Reheater        |
| Fans                         | Induced Draft Fans      | Induced Draft Fans      | Induced Draft Fans          | Induced Draft Fans             |
| Sulfur Disposal/Recovery     | Lined Settling Pond     | Lined Settling Pond     | Production of Sulfuric Acid | Production of Elemental Sulfur |
|                              |                         |                         |                             | Lined Settling Pond            |

\*Selection of processing techniques was based on data from the open literature which were representative of commercially available systems.

cause corrosion problems. Similarly, higher levels of solids in the recirculating liquor may cause increased equipment erosion. In light of these potential problems, venturi prescrubbers were included in this study for the limestone and lime processes.

### SO<sub>2</sub> Scrubbing

There are many types of SO<sub>2</sub> absorbers available. Often the choice of absorber type is determined by the preference or experience of the company designing the system. The selection of the SO<sub>2</sub> absorbers indicated in Table 3-3 was based upon two criteria:

- 1) they have been used in commercial applications or demonstration tests and
- 2) data on the operation of the absorber were available in the open literature.

### Reheat

Indirect steam reheaters were selected for all of the FGD processes. An alternative to this choice is combustion of an auxiliary fuel, such as natural gas or fuel oil, and direct injection of the hot combustion gases into the flue gas. Steam reheaters were chosen because of the availability of steam from the power plant and the uncertainty of future natural gas and fuel oil supplies.

The minimum stack exit temperature required to prevent sulfuric acid mist formation and provide plume buoyancy is not well defined. Common practice, and the design basis for this study, is to reheat the scrubbed gas to achieve an exit temperature of 353°K (175°F). Changing the reheat temperature a few degrees can significantly effect this energy requirement.

This in turn can effect the energy requirements of the whole FGD process since reheat accounts for 35 to 45 percent of the energy requirements for nonregenerable FGD systems and 10 to 20 percent of the requirements for regenerable FGD systems.

### Fans

Either induced draft (I.D.) or forced draft (F.D.) fans can be used to maintain gas flow through the scrubbing systems. I.D. fans require about 10 percent less energy than F.D. fans. However, a potential disadvantage of I.D. fans is their susceptibility to corrosion if scrubbing liquor is entrained in the flue gas exiting the SO<sub>2</sub> absorbers. For this study, I.D. fans were selected for all of the FGD processes because of their lower energy consumption.

### Sulfur Disposal/Recovery

The limestone, lime and double-alkali FGD processes produce a calcium sulfite/sulfate sludge. Ponding is the normal on-site method of sludge disposal. Off-site disposal methods require sludge stabilization to produce an acceptable landfill material. On-site disposal in lined settling ponds was selected for this study.

Both the MgO and W-L/A processes produce an SO<sub>2</sub> stream from regeneration of the SO<sub>2</sub> scrubbing liquor. In the Wellman-Lord/Allied process evaporator/crystallizers are used to regenerate the SO<sub>2</sub> scrubbing liquor. For this study and in previous commercial designs of the Wellman-Lord/Allied process, single-effect evaporators were used. The use of a double-effect evaporator would reduce the energy requirements for regeneration by about 45 percent at the expense of increased capital costs (OT-051). Because the regeneration operation produces a

concentrated (>90 percent) SO<sub>2</sub> stream (OT-051), conversion to elemental sulfur or sulfuric acid is possible. For this study, a proprietary process of the Allied Chemical Company was selected for converting the SO<sub>2</sub> to elemental sulfur.

In the MgO process, oil-fired dryers and calciners are used to decompose MgSO<sub>3</sub> into recycle MgO and a dilute (<10 percent) SO<sub>2</sub> stream. Although the SO<sub>2</sub> can be converted into sulfur or sulfuric acid, conversion to sulfuric acid was chosen because the SO<sub>2</sub> stream also contains 5 to 10 percent O<sub>2</sub> (OT-051, ZO-008). The O<sub>2</sub> is beneficial to the production of sulfuric acid, but it increases the quantity of reducing gas required to produce elemental sulfur.

### 3.2.2 Design Assumptions for Physical Coal Cleaning

Several of the model SO<sub>2</sub> control systems selected by the EPA for this study included examination of physical cleaning of high sulfur eastern coals and then combusting the cleaned coal using an FGD system. This approach to utilizing coal cleaning as an SO<sub>2</sub> control technique is not commonly practiced in the utility industry where economic considerations are of vital importance. Coal cleaning plants specifically designed for sulfur removal generally produce three coal products. One product has a sulfur content low enough to be combusted, without using an FGD process, in power plants which have to comply with the SO<sub>2</sub> emission standard for new sources. A second product fraction with a slightly higher sulfur content can be combusted without SO<sub>2</sub> controls in plants which have to comply with the emission standard for existing sources. The third product fraction has a very low heat content and must be blended with raw coal or one of the clean coal products. Combustion of this blend will require flue gas desulfurization. To conform with the emission control systems defined by the EPA, the three clean coal products

produced by a coal cleaning plant are assumed to be combined and combusted in one power plant. The compositions of the physically cleaned eastern coals and the assumptions used in calculating these compositions are shown in Table 3-4.

TABLE 3-4. COMPOSITIONS OF PHYSICALLY CLEANED COALS

|                                   | Physically cleaned<br>3.5% sulfur coal | Physically cleaned<br>7.0% sulfur coal |
|-----------------------------------|----------------------------------------|----------------------------------------|
| Moisture, Ash Free<br>Coal, wt. % | 87.1                                   | 87.1                                   |
| Ash, wt. %                        | 6.6                                    | 6.6                                    |
| H <sub>2</sub> O, wt. %           | 6.3                                    | 6.3                                    |
| Sulfur, wt. %                     | 2.2                                    | 4.4                                    |
| Heating Value, MJ/kg              | 29.2                                   | 29.2                                   |

#### Assumptions

- 50% ash removal
- 40% sulfur removal
- 95% energy recovery efficiency (RO-325)
- 50% of product coal is thermally dried (CH-307)
- heat for thermal dryer is supplied by combusting product coal

#### 3.2.3 Design Assumptions for Coal Transportation

The unit train is the most economic method for transporting coal by rail over long distances on a continual basis. There are several economic advantages of unit trains. They employ specially designed hopper cars and locomotives. Minimal time loading and unloading is required, so equipment usage is maximized. The following assumptions were used in calculating the energy requirements of the unit trains examined in this study:

- 1) Total one-way train distance between coal mine and power plant is 2,100 km (1300 miles).

- 2) Each unit train consists of 100 coal cars with a coal capacity of 91,000 kg (100 ton) (WH-101).
- 3) Each unit train uses 5 locomotives rated at 2,700 kW (3,600 HP) with the following diesel fuel oil consumption (WH-101, RA-215):
  - At full power: 0.00021 m<sup>3</sup>/s (200 gal/hr) per locomotive
  - At reduced power: 0.000029 m<sup>3</sup>/s (28 gal/hr) per locomotive
- 4) Four hours each are required for loading and unloading while the train moves at reduced power (BU-116, RA-215).
- 5) One hour is required for passing a large city and for undergoing each federal inspection, while the train moves at reduced power (BU-116, RA-215).
- 6) One large city every 180 km (110 miles) and one federal inspection every 800 km (500 miles).
- 7) Average train speed in open country is 48 km/hr (30 mph) when loaded and 96 km/hr (60 mph) when empty (SO-138).
- 8) One percent of the total train load is lost as coal dust blow-off which occurs primarily during loading and unloading (CO-129).

The model power plant/SO<sub>2</sub> emission control systems selected by the EPA for examination in this study are shown in Table 4-1. The systems include thirteen control cases, which are grouped under three emission control levels. Energy requirements for the control systems were calculated from the base case data and extrapolation methods described in Appendices A through G. In Section 4.1, these energy requirements are compared with respect to the techniques used to control SO<sub>2</sub> emission and with respect to the three SO<sub>2</sub> control levels.

The energy requirements for the model control systems were also compared with total U.S. energy demands in 1987 and 1997. Growth projections for the coal-fired segment of the electric power industry and for total U.S. energy consumption were obtained for the years 1987 and 1997. The energy penalties imposed by the various SO<sub>2</sub> emission control systems were multiplied by the projected capacities of the new emission sources. The resulting total energy penalty data were then compared to the total U.S. energy demand. Section 4.2 summarizes the results of these comparisons.

## 4.1

SO<sub>2</sub> Control Systems Comparisons

A process operation breakdown of the energy requirements for each FGD process shows that energy requirements for some of the operations depend on the amount of SO<sub>2</sub> removed and/or degree of SO<sub>2</sub> removal. There are six energy consuming operations in the FGD processes:

- Raw material handling and feed preparation,
- Particulate/chloride removal,

TABLE 4-1. MODEL SO<sub>2</sub> EMISSION CONTROL SYSTEMS STUDIED

| SO <sub>2</sub> Control Level                                            | Plant Sizes Considered, MW | FGD Processes Considered* | Coal                                                                      |
|--------------------------------------------------------------------------|----------------------------|---------------------------|---------------------------------------------------------------------------|
| 0.52 g SO <sub>2</sub> /MJ (1.2 lb SO <sub>2</sub> /10 <sup>6</sup> Btu) | 25, 100, 500, 1000         | LS, L, MgO, W-L/A, D-A    | 3.5% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500, 1000         | LS, L                     | 7.0% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 500                    | ---                       | 0.6% sulfur; 20.9 MJ/kg western coal transported to a Midwest power plant |
|                                                                          | 25, 500                    | ---                       | 0.8% sulfur; 25.6 MJ/kg western coal transported to a Midwest power plant |
|                                                                          | 500                        | LS, L                     | 2.3% sulfur; 29.2 MJ/kg**                                                 |
| 90% SO <sub>2</sub> Removal by FGD                                       | 25, 100, 500, 1000         | LS, L, MgO, W-L/A, D-A    | 3.5% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500, 1000         | LS, L, MgO, W-L/A, D-A    | 7.0% sulfur; 27.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500               | LS, L                     | 0.8% sulfur; 20.9 MJ/kg                                                   |
|                                                                          | 25, 100, 500               | LS, L                     | 0.8% sulfur; 25.6 MJ/kg                                                   |
|                                                                          | 25, 500                    | LS, L                     | 0.8% sulfur; 20.9 MJ/kg                                                   |
| 0.22 g SO <sub>2</sub> /MJ (0.5 lb SO <sub>2</sub> /10 <sup>6</sup> Btu) | 25, 500                    | LS, L                     | 0.8% sulfur; 20.9 MJ/kg                                                   |
|                                                                          | 25, 500                    | LS, L                     | 0.8% sulfur; 25.6 MJ/kg                                                   |
|                                                                          | 25, 500                    | LS, L                     | 2.3% sulfur; 29.2 MJ/kg**                                                 |
|                                                                          | 25, 500                    | LS, L                     | 4.6% sulfur; 29.2 MJ/kg***                                                |

\*LS = Limestone

L = Lime

MgO = Magnesia Slurry

W-L/A = Wellman-Lord/Allied

D-A = Double-Alkali

\*\*Physically cleaned 3.5% sulfur; 27.9 MJ/kg coal (40% sulfur removal)

\*\*\*Physically cleaned 7.0% sulfur; 27.9 MJ/kg coal (40% sulfur removal)

- SO<sub>2</sub> scrubbing,
- Reheat,
- Fans, and
- Sulfur recovery/disposal.

The energy requirements for these operations are listed in Table 4-2 for a 500 MW plant using 3.5 and 7.0 percent sulfur coals.

For the nonregenerable FGD processes--limestone, lime and double-alkali--particulate/chloride scrubbers, reheaters, and fans account for 65 to 90 percent of the total system energy requirements. The remaining energy requirements are for the SO<sub>2</sub> scrubbers, raw material handling, and feed preparation. Minimal amounts are required for calcium sulfite/sulfate sludge disposal. Since only the energy requirements for these latter three operations depend on the amount of SO<sub>2</sub> removed, the energy requirements for nonregenerable FGD processes are relatively insensitive to changes in coal sulfur content and SO<sub>2</sub> removal level.

For the regenerable FGD processes--magnesia slurry and Wellman-Lord/Allied--the sulfur recovery operations account for a large majority of the total system energy requirements (55 to 65 percent for the MgO process and 80 to 85 percent for the W-L/A process). Since the energy requirements of the sulfur recovery operations depend directly on the amount of SO<sub>2</sub> removed from the flue gas, the total system energy requirements are strongly dependent on the sulfur content of the coal and the SO<sub>2</sub> removal level.

It may be of interest to examine the energy requirements of "bare bones" SO<sub>2</sub> control systems. For the limestone and lime FGD systems, this would entail deleting the energy requirements associated with particulate/chloride removal and flue gas reheat. For the magnesia slurry, W-L/A and double-alkali

TABLE 4-2. ENERGY REQUIREMENTS FOR THE PROCESSING OPERATIONS IN FGD SYSTEMS

| FGD Process         | Coal Sulfur Content | Raw Material Handling and Preparation | Energy Requirements for Flue Gas Desulfurization, MJ/s |                           |        |       |                          | Total System Energy Requirements** |
|---------------------|---------------------|---------------------------------------|--------------------------------------------------------|---------------------------|--------|-------|--------------------------|------------------------------------|
|                     |                     |                                       | Particulate/Chloride Removal                           | SO <sub>2</sub> Scrubbing | Reheat | Fans  | Sulfur Recovery/Disposal |                                    |
| Limestone           | 3.5%                | 2.2                                   | 9.0*                                                   | 8.8                       | 18.3   | 10.4* | 0.3                      | 49.2                               |
|                     | 7.0%                | 4.4                                   | 9.0*                                                   | 13.5                      | 18.5   | 11.1* | 0.6                      | 57.3                               |
| Lime                | 3.5%                | 0.2                                   | 9.0*                                                   | 6.3                       | 18.3   | 10.2* | 0.3                      | 44.3                               |
|                     | 7.0%                | 0.4                                   | 9.0*                                                   | 9.4                       | 18.3   | 10.4* | 0.5                      | 48.2                               |
| Magnesia Slurry     | 3.5%                | 0.5                                   | 3.0                                                    | 2.5                       | 15.3   | 14.7  | 41.1                     | 77.5                               |
|                     | 7.0%                | 0.9                                   | 3.0                                                    | 5.0                       | 15.4   | 16.1  | 82.8                     | 124                                |
| Wellman-Lord/Allied | 3.5%                | 0.2                                   | 3.0                                                    | 0.9                       | 16.8   | 18.3  | 136                      | 176                                |
|                     | 7.0%                | 0.3                                   | 3.1                                                    | 0.9                       | 17.3   | 18.8  | 281                      | 321                                |
| Double-Alkali       | 3.5%                | 0.3                                   | 3.0                                                    | 2.4                       | 18.2   | 14.9  | 0.7                      | 39.8                               |
|                     | 7.0%                | 0.5                                   | 3.0                                                    | 2.4                       | 18.2   | 14.9  | 1.3                      | 40.7                               |

\*Energy required by fans to overcome pressure drop associated with particulate removal is included in the particulate removal operation.

\*\*Utilities and Services for the FGD processes account for the discrepancies in system totals.

#### Assumptions

500 MW power plant (net generating capacity)

90% SO<sub>2</sub> removal

Uncontrolled power plant net heat rate = 2640 J/kW-h

Steam produced in Magnesia Slurry and Wellman-Lord/Allied process is used within the process.

Magnesia Slurry process produces sulfuric acid as a by-product.

Wellman-Lord/Allied process produces sulfur as a by-product.

processes, this entails deleting only the energy for reheat since the removal of chlorides is essential to the operation of these FGD systems. Table 4-3 compares the energy requirements for "bare bones" SO<sub>2</sub> control systems to the control systems presented in Table 4-2.

TABLE 4-3. COMPARISON OF TOTAL SYSTEM *vs.* "BARE BONES"  
SYSTEM ENERGY REQUIREMENTS

| FGD Process             | Coal Sulfur Content | Total System Energy Requirements, MJ/s | "Bare Bones" System Energy Requirements, MJ/s | Percentage Difference |
|-------------------------|---------------------|----------------------------------------|-----------------------------------------------|-----------------------|
| Limestone               | 3.5%                | 49.2                                   | 21.9                                          | 55                    |
|                         | 7.0%                | 57.3                                   | 29.8                                          | 48                    |
| Lime                    | 3.5%                | 44.3                                   | 17.0                                          | 62                    |
|                         | 7.0%                | 48.2                                   | 20.9                                          | 57                    |
| Magnesia Slurry         | 3.5%                | 77.5                                   | 59.2                                          | 24                    |
|                         | 7.0%                | 124                                    | 106                                           | 15                    |
| Wellman-Lord/<br>Allied | 3.5%                | 176                                    | 156                                           | 12                    |
|                         | 7.0%                | 321                                    | 301                                           | 6                     |
| Double-Alkali           | 3.5%                | 39.8                                   | 18.6                                          | 53                    |
|                         | 7.0%                | 40.7                                   | 19.5                                          | 52                    |

Assumptions

500 MW power plant (net generating capacity)

90% SO<sub>2</sub> removal

Uncontrolled power plant net heat rate = 2640 J/kW-s

Steam produced in Magnesia Slurry and Wellman-Lord/Allied processes is used within the process.

Magnesia Slurry process produces sulfuric acid as a by-product.

Wellman-Lord/Allied process produces sulfur as a by-product.

Estimates of the energy requirements, including the energy required for particulate/chloride removal and flue gas reheat, are listed in Tables 4-4 through 4-6. The data in these tables can be expressed in several ways. Two methods were chosen for this study. First, the energy requirements were divided by the net electrical generating capacity of the power plant to give J/s/kW or J/kW-s. Expressing the data in this manner permits the data to be extrapolated to power plant capacities other than those considered in this study. For example, a 400 MW (400,000 kW) power plant may have design and operating parameters,

TABLE 4-4. ENERGY PENALTIES FOR MODEL SO<sub>2</sub> CONTROL SYSTEMS  
USING LIMESTONE SCRUBBING

|                         |                               | SO <sub>2</sub> Control Penalty, J/kW-s<br>(% of energy input to uncontrolled plant) |            |           |            |           |
|-------------------------|-------------------------------|--------------------------------------------------------------------------------------|------------|-----------|------------|-----------|
| Coal                    | SO <sub>2</sub> Control Level | Control Technique                                                                    | 25 MW      | 100 MW    | 500 MW     | 1000 MW   |
| 3.5% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | FGD                                                                                  | 90 ( 3.3)  | 90 (3.3)  | 90 ( 3.4)  | 80 (3.1)  |
| 7.0% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | FGD                                                                                  | 120 ( 4.4) | 120 (4.4) | 110 ( 4.2) | 110 (4.3) |
| 0.6% Sulfur; 20.9 MJ/kg | Uncontrolled                  | Transporting western coal to Midwest                                                 | 170 ( 6.2) | NE        | 170 ( 6.4) | NE        |
| 0.8% Sulfur; 25.6 MJ/kg | Uncontrolled                  | Transporting western coal to Midwest                                                 | 150 ( 5.5) | NE        | 140 ( 5.3) | NE        |
| 2.2% Sulfur; 29.2 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | Coal cleaning & FGD                                                                  | NE         | NE        | 260 ( 9.8) | NE        |
| 3.5% Sulfur; 27.9 MJ/kg | 90% removal                   | FGD                                                                                  | 100 ( 3.7) | 100 (3.7) | 100 ( 3.8) | 90 (3.5)  |
| 7.0% Sulfur; 27.9 MJ/kg | 90% removal                   | FGD                                                                                  | 120 ( 4.4) | 120 (4.4) | 110 ( 4.2) | 110 (4.3) |
| 0.8% Sulfur; 20.9 MJ/kg | 90% removal                   | FGD                                                                                  | 90 ( 3.3)  | 90 (3.3)  | 90 ( 3.4)  | NE        |
| 0.8% Sulfur; 25.6 MJ/kg | 90% removal                   | FGD                                                                                  | 90 ( 3.3)  | 90 (3.3)  | 90 ( 3.4)  | NE        |
| 0.8% Sulfur; 20.9 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | FGD                                                                                  | 80 ( 2.9)  | NE        | 80 ( 3.0)  | NE        |
| 0.8% Sulfur; 25.6 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | FGD                                                                                  | 80 ( 2.9)  | NE        | 80 ( 3.0)  | NE        |
| 2.2% Sulfur; 29.2 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | Coal cleaning & FGD                                                                  | 280 (10.3) | NE        | 270 (10.2) | NE        |
| 4.4% Sulfur; 29.2 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | Coal cleaning & FGD                                                                  | 300 (11.0) | NE        | 290 (11.0) | NE        |

NE - not examined

Uncontrolled power plant net heat rates:

- 25 MW - 2720 J/kW-s
- 100 MW - 2710 J/kW-s
- 500 MW - 2640 J/kW-s
- 1000 MW - 2550 J/kW-s

TABLE 4-5. ENERGY PENALTIES FOR MODEL SO<sub>2</sub> CONTROL SYSTEM  
USING LIME SCRUBBING

| Coal                    | SO <sub>2</sub> Control Level | Control Technique   | SO <sub>2</sub> Control Penalty, J/kW-s<br>(% of energy input to uncontrolled plant) |           |            |          |
|-------------------------|-------------------------------|---------------------|--------------------------------------------------------------------------------------|-----------|------------|----------|
|                         |                               |                     | 25 MW                                                                                | 100 MW    | 500 MW     | 1000 MW  |
| 3.5% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | FGD                 | 90 (3.3)                                                                             | 90 (3.3)  | 80 (3.0)   | 80 (3.1) |
| 7.0% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | FGD                 | 100 (3.7)                                                                            | 100 (3.7) | 100 (3.8)  | 90 (3.5) |
| 2.2% Sulfur; 29.2 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | Coal cleaning & FGD | NE                                                                                   | NE        | 260 (9.8)  | NE       |
| 3.5% Sulfur; 27.9 MJ/kg | 90% removal                   | FGD                 | 90 (3.3)                                                                             | 90 (3.3)  | 90 (3.4)   | 90 (3.5) |
| 7.0% Sulfur; 27.9 MJ/kg | 90% removal                   | FGD                 | 100 (3.7)                                                                            | 100 (3.7) | 100 (3.8)  | 90 (3.5) |
| 0.8% Sulfur; 20.9 MJ/kg | 90% removal                   | FGD                 | 90 (3.3)                                                                             | 90 (3.3)  | 80 (3.0)   | NE       |
| 0.8% Sulfur; 25.6 MJ/kg | 90% removal                   | FGD                 | 90 (3.3)                                                                             | 90 (3.3)  | 80 (3.0)   | NE       |
| 0.8% Sulfur; 20.9 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | FGD                 | 80 (2.9)                                                                             | NE        | 80 (3.0)   | NE       |
| 0.8% Sulfur; 25.6 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | FGD                 | 80 (2.9)                                                                             | NE        | 80 (3.0)   | NE       |
| 2.2% Sulfur; 29.2 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | Coal cleaning & FGD | 270 (9.9)                                                                            | NE        | 260 (9.8)  | NE       |
| 4.4% Sulfur; 29.2 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | Coal cleaning & FGD | 280 (10.3)                                                                           | NE        | 270 (10.2) | NE       |

NE - not examined

Uncontrolled power plant net heat rates:

- 25 MW - 2720 J/kW-s
- 100 MW - 2710 J/kW-s
- 500 MW - 2640 J/kW-s
- 1000 MW - 2550 J/kW-s

TABLE 4-6. ENERGY PENALTIES FOR MODEL SO<sub>2</sub> CONTROL SYSTEMS USING MAGNESIA SLURRY, WELLMAN-LORD/ALLIED AND DOUBLE-ALKALI SCRUBBING

| Coal                    | SO <sub>2</sub> Control Level | Control Technique | SO <sub>2</sub> Control Penalty, J/kW-s<br>(% of energy input to uncontrolled plant) |            |            |            |
|-------------------------|-------------------------------|-------------------|--------------------------------------------------------------------------------------|------------|------------|------------|
|                         |                               |                   | 25 MW                                                                                | 100 MW     | 500 MW     | 1000 MW    |
| 3.5% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | MgO FGD           | 150 ( 5.5)                                                                           | 150 ( 5.5) | 140 ( 5.3) | 130 ( 5.1) |
|                         | 90% removal                   | MgO FGD           | 160 ( 5.9)                                                                           | 160 ( 5.9) | 160 ( 6.1) | 150 ( 5.9) |
|                         | 90% removal                   | MgO FGD           | 260 ( 9.6)                                                                           | 260 ( 9.6) | 250 ( 9.5) | 240 ( 9.4) |
| 3.5% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | W-L/A FGD         | 320 (11.8)                                                                           | 320 (11.8) | 310 (11.7) | 290 (11.4) |
|                         | 90% removal                   | W-L/A FGD         | 360 (13.2)                                                                           | 360 (13.3) | 350 (13.2) | 340 (13.3) |
|                         | 90% removal                   | W-L/A FGD         | 710 (26.1)                                                                           | 700 (25.8) | 680 (25.8) | 660 (25.9) |
| 3.5% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | D-A FGD           | 80 ( 2.9)                                                                            | 80 ( 3.0)  | 80 ( 3.0)  | 80 ( 3.1)  |
|                         | 90% removal                   | D-A FGD           | 80 ( 2.9)                                                                            | 80 ( 3.0)  | 80 ( 3.0)  | 80 ( 3.1)  |
|                         | 90% removal                   | D-A FGD           | 90 ( 3.3)                                                                            | 90 ( 3.3)  | 80 ( 3.0)  | 80 ( 3.1)  |

Uncontrolled power plant net heat rates:

- 25 MW - 2720 J/kW-s
- 100 MW - 2710 J/kW-s
- 500 MW - 2640 J/kW-s
- 1000 MW - 2550 J/kW-s

including uncontrolled net plant heat rate, similar to one of the 500 MW plants considered in this study. The energy penalty data for the 500 MW plant can then be multiplied by 400,000 kW to determine the energy penalty for the 400 MW plant.

The second method of expressing the energy penalty data is as a percent of the energy input to an uncontrolled plant with the same net heat rate and net generating capacity. This method identifies, for a given generating capacity, the percentage increase in energy consumption resulting from control of SO<sub>2</sub> emissions.

An examination of the data in Tables 4-4 through 4-6 shows that on a per kilowatt or percentage basis, power plant capacity has little influence on the energy requirements of the emission control systems. Therefore, it is only necessary to look at one plant capacity to compare the different levels and means of controlling SO<sub>2</sub> emissions. Since 500 MW plants were examined for all thirteen control cases, the data for this plant capacity were selected for the comparative analyses.

#### 4.1.1 Comparison by SO<sub>2</sub> Control Level

Three SO<sub>2</sub> emission control levels were examined:

- 0.52 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input (the existing NSPS)
- 90% SO<sub>2</sub> removal by FGD
- 0.22 g SO<sub>2</sub>/MJ (0.5 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input

Comparisons of the energy requirements for the control systems achieving these three control levels are presented in the following sections.

0.52 g SO<sub>2</sub>/MJ

The energy requirements for the five cases which control SO<sub>2</sub> emissions to the existing NSPS of 0.52 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input are shown in Figure 4-1. In addition to indicating the total energy penalties for the control cases, the data in Figure 4-1 are separated into the type of energy required, *i.e.*, steam, electricity, natural gas or fuel oil for the FGD process, diesel fuel oil for unit trains and coal losses from physical coal cleaning or transporting coal. The following observations can be made from the data in Figure 4-1:

- The smallest energy penalty is imposed by use of the nonregenerable FGD processes.
- The three nonregenerable FGD processes (limestone, lime and double-alkali) impose approximately equal energy penalties. The limestone process requires slightly more energy than the lime and double-alkali processes.
- Of the two regenerable FGD processes, the Wellman-Lord/Allied process requires over twice as much energy as the MgO process.
- Shipping low sulfur western coal to the Midwest requires from 25 to over 100 percent more energy than burning a high sulfur coal and using a nonregenerable FGD process.
- Physically cleaning coal prior to combustion and also using the limestone or lime FGD

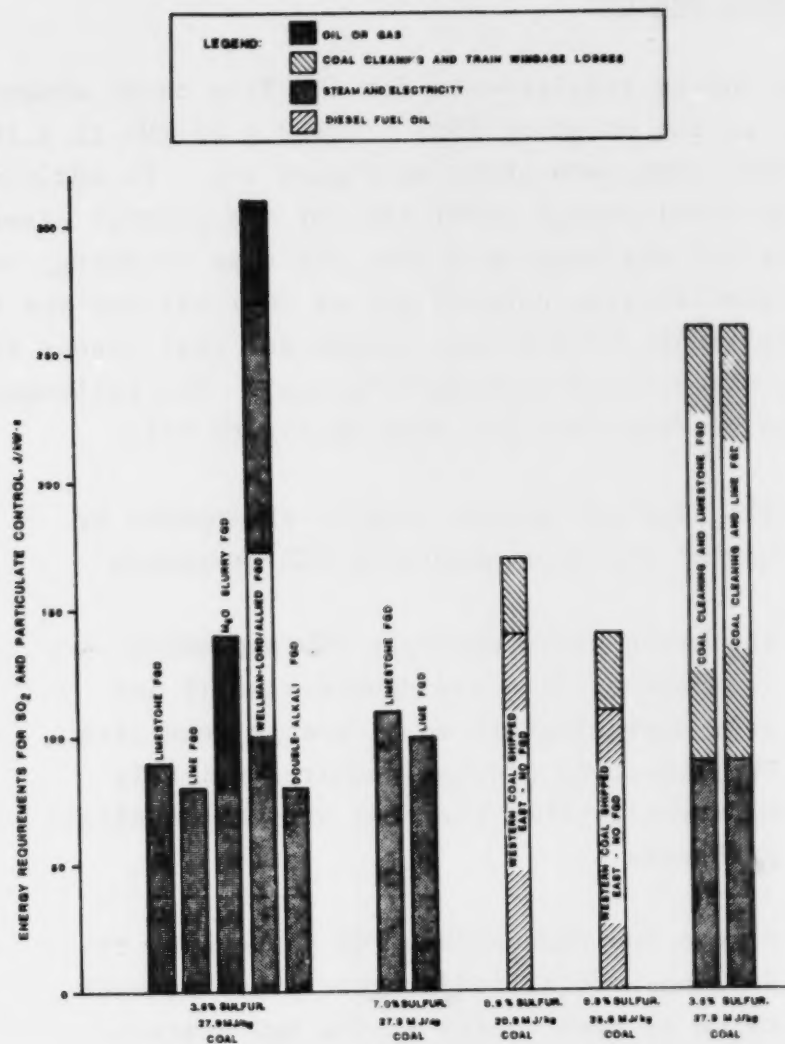


Figure 4-1. Energy requirements for SO<sub>2</sub> and particulate control - 0.52 g SO<sub>2</sub>/MJ control level, 500 MW plant.

process requires about three times the energy required when only the FGD process is used.

#### 90% SO<sub>2</sub> Removal by FGD

The energy requirements for the four control cases which achieve 90 percent SO<sub>2</sub> removal are shown in Figure 4-2. As was true for the 0.52 g SO<sub>2</sub>/MJ control level, use of any of the nonregenerable FGD processes requires about the same amount of energy and the nonregenerable FGD processes impose much less of an energy penalty than the regenerable FGD processes. With respect to changes in the sulfur content of the coal, the energy requirements of the nonregenerable FGD processes change very little (about a 10 percent increase when the sulfur content of the coal doubles from 3.5 to 7.0 percent). However, the energy requirements of the regenerable FGD processes show a strong dependence on the sulfur content of the coal. Doubling the coal sulfur content from 3.5 to 7.0 percent increases the energy requirements of the MgO process by about 50 percent and of the Wellman-Lord/Allied process by about 100 percent. This arises because the SO<sub>2</sub> recovery operations represent 55 to 85 percent of the energy required by these processes.

#### 0.22 g SO<sub>2</sub>/MJ

The energy requirements for the four cases which control SO<sub>2</sub> emission to 0.22 g SO<sub>2</sub>/MJ (0.5 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input are shown in Figure 4-3. As for the other two control levels, the energy requirements of the limestone and lime FGD processes are essentially equal. The two control cases which include physical coal cleaning followed by use of the lime or limestone FGD process again illustrate the significant energy penalty associated with physical coal cleaning.

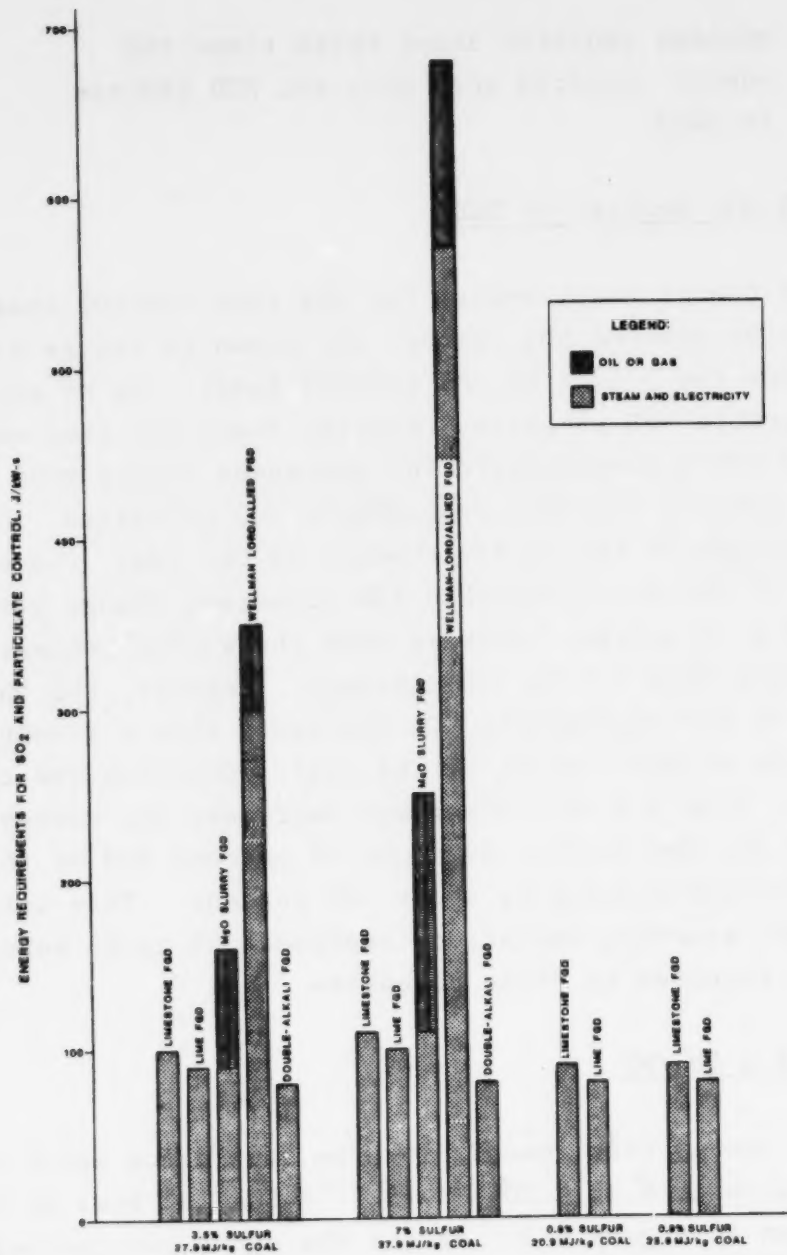


Figure 4-2. Energy penalties for SO<sub>2</sub> and particulate control - 90% removal control level, 500 MW plant.

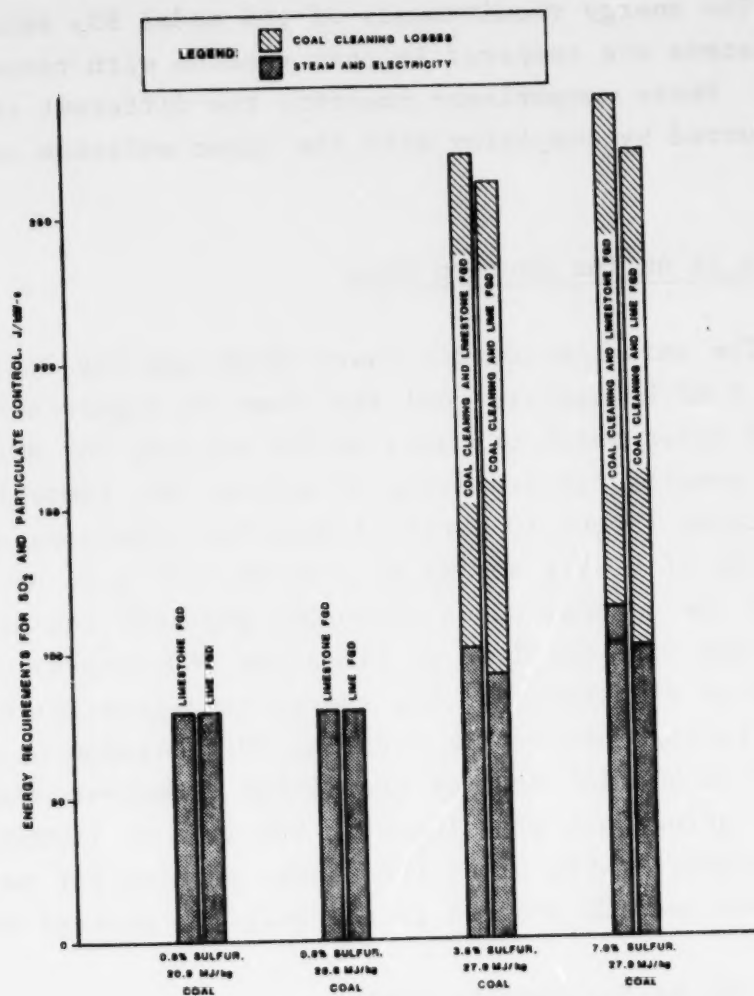


Figure 4-3. Energy requirements for SO<sub>2</sub> and particulate control - 0.22 g SO<sub>2</sub>/MJ control level, 500 MW plant.

#### 4.1.2 Comparison by Coal Used

The energy requirements of the model SO<sub>2</sub> emission control systems are compared in this section with respect to the coal used. These comparisons identify the different energy penalties incurred by complying with the three emission control levels.

##### 3.5% Sulfur Eastern Coal

The emission control cases which use the 3.5 percent sulfur, 27.9 MJ/kg eastern coal are shown in Figure 4-4. For the control cases which use only an FGD process for SO<sub>2</sub> control, the energy penalty for achieving 90 percent SO<sub>2</sub> removal is only slightly higher (about 10 percent) than for complying with the existing NSPS of 0.52 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input. For the control cases which use physical coal cleaning in conjunction with the lime or limestone FGD process, there is essentially no difference in the energy penalties for complying with the existing NSPS or for reducing SO<sub>2</sub> emission to 0.22 g SO<sub>2</sub>/MJ (1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input. However, the energy penalty for using coal cleaning with the lime or limestone FGD process is almost three times the energy penalty for using the lime or limestone FGD process as the only SO<sub>2</sub> control technique.

##### 7.0% Sulfur Eastern Coal

The energy requirements for the three control cases which utilized the 7.0 percent sulfur coal are shown in Figure 4-5. For the limestone and lime FGD processes the energy penalty for achieving 90 percent SO<sub>2</sub> removal is about equal to the penalty for meeting the existing NSPS. Physical coal cleaning followed by FGD requires over one and one-half times the energy that is required by FGD alone.

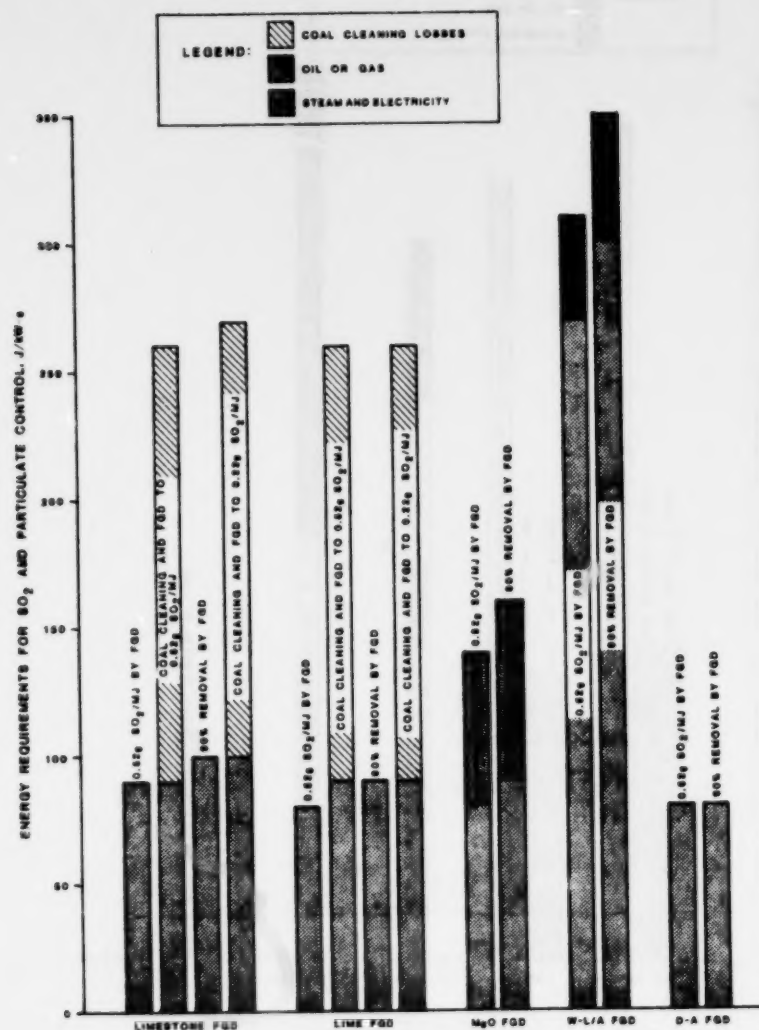


Figure 4-4. Energy requirements for SO<sub>2</sub> and particulate control - 3.5% sulfur coal, 500 MW plant

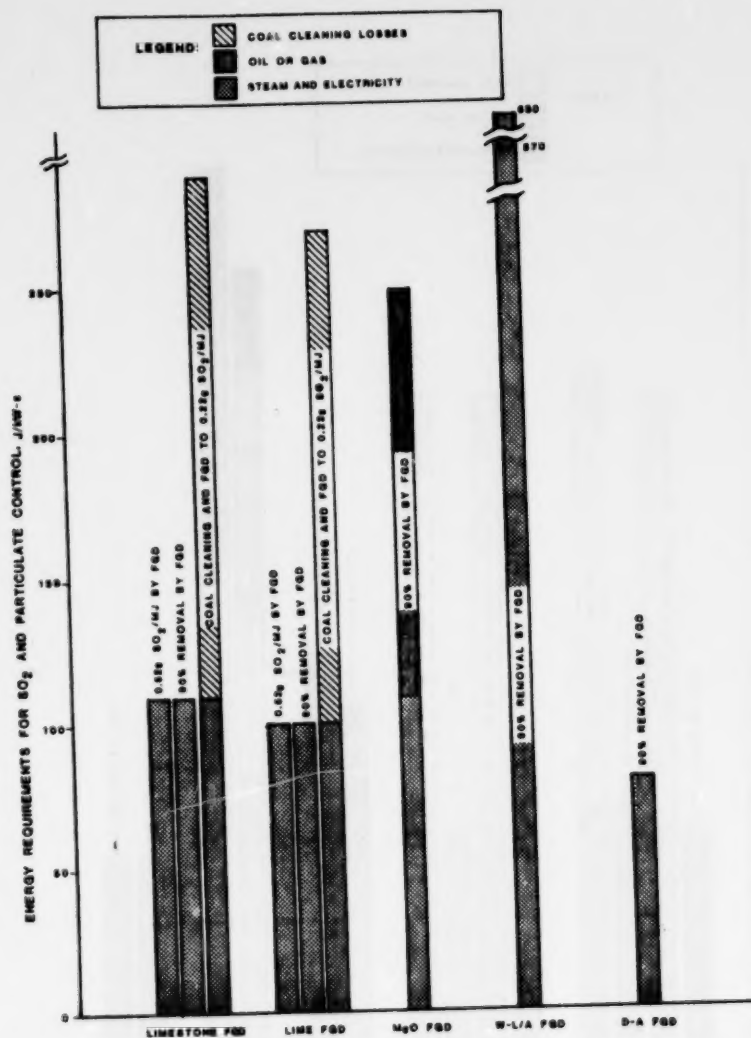


Figure 4-5. Energy requirements for SO<sub>2</sub> and particulate control - 7.0% sulfur coal, 500 MW plant.

### Low Sulfur Western Coals

The energy requirements for the four control cases which utilize the low sulfur western coals are shown in Figures 4-6 and 4-7. The data in these figures show the very small difference in energy requirements for using the limestone or lime FGD process to achieve either 90 percent SO<sub>2</sub> removal or 0.22 g SO<sub>2</sub>/MJ (0.5 lb SO<sub>2</sub>/10<sup>6</sup> Btu) of heat input. This is expected due to the similar properties of the two western coals.

#### 4.2 Energy Penalty Projections

The following projections of new coal-fired electric generating capacity which would be affected by a revised SO<sub>2</sub> new source performance standard were supplied by the EPA:

| <u>New Coal-Fired Generating Capacity</u> |            |
|-------------------------------------------|------------|
| 1983 through 1987                         | 65,000 MW  |
| 1983 through 1997                         | 316,000 MW |

The EPA also indicated that the average annual operating factor for this new capacity would be 65 percent. The energy penalty data presented previously were used with these capacity projections to estimate the future effect of a revised NSPS on the energy penalties of SO<sub>2</sub> emission controls. It was assumed for these calculations that the new capacity would be installed in the form of 500 MW power plants. However, the mix of coal feeds and SO<sub>2</sub> control methods for these new plants and future SO<sub>2</sub> emission standards were not known. In order to illustrate what the minimum and maximum energy penalties may be, the projected new generating capacities were multiplied by the energy requirements for each of the 500 MW model power plant/SO<sub>2</sub> control systems. These estimated energy penalties for 1987 and 1997 are listed in Table 4-7 and 4-8, respectively.

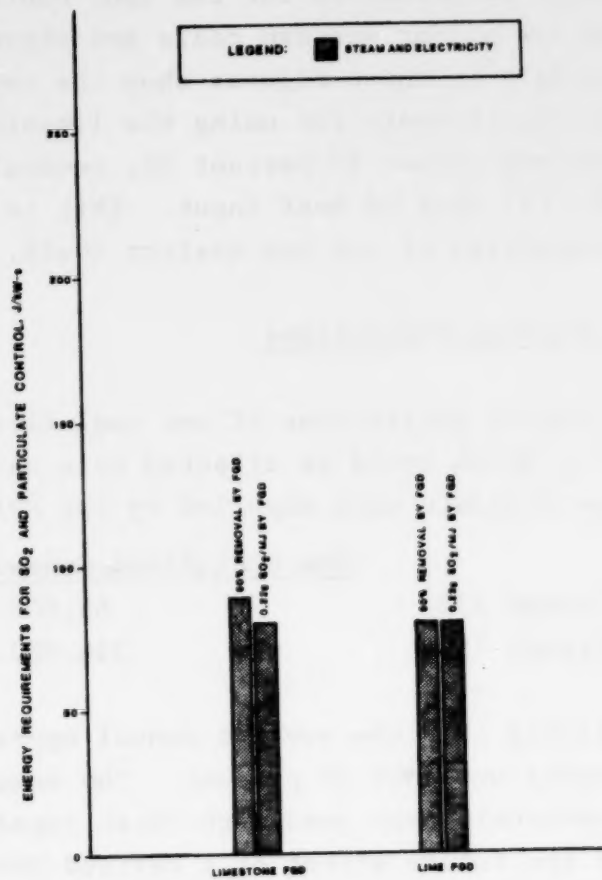


Figure 4-6. Energy requirements for SO<sub>2</sub> and particulate control - low heating value Western coal, 500 MW plant.

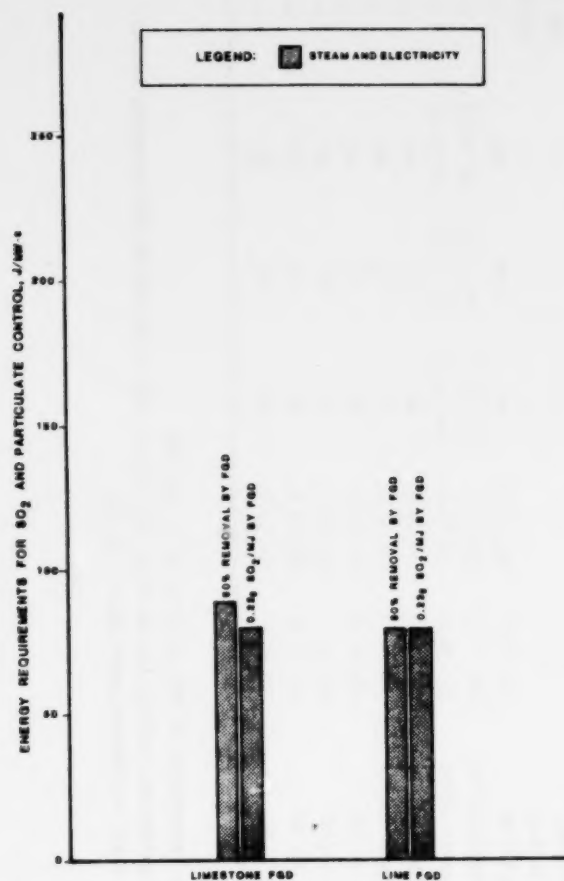


Figure 4-7. Energy requirements for SO<sub>2</sub> and particulate control - high heating value Western coal 500 MW plant.

TABLE 4-7. PROJECTED SO<sub>2</sub> EMISSION CONTROL ENERGY PENALTIES--1987

| Coal                    | SO <sub>2</sub> Control Level | Projected SO <sub>2</sub> Emission Control Energy Penalty in 1987, 10 <sup>15</sup> J/yr<br>(% of Total U.S. Energy Consumption) |           |           |           |           | Coal            |  |
|-------------------------|-------------------------------|----------------------------------------------------------------------------------------------------------------------------------|-----------|-----------|-----------|-----------|-----------------|--|
|                         |                               | Limestone                                                                                                                        | Line      | MgO       | W-L/A     | D-A       | Transportation* |  |
| 3.5% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | 120 (0.1)                                                                                                                        | 110 (0.1) | 190 (0.2) | 420 (0.4) | 110 (0.1) | --              |  |
| 7.0% Sulfur; 27.9 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | 150 (0.1)                                                                                                                        | 130 (0.1) | NE        | NE        | NE        | --              |  |
| 0.6% Sulfur; 20.9 MJ/kg | Uncontrolled                  | --                                                                                                                               | --        | --        | --        | --        | 230 (0.2)       |  |
| 0.8% Sulfur; 26.5 MJ/kg | Uncontrolled                  | --                                                                                                                               | --        | --        | --        | --        | 190 (0.2)       |  |
| 2.3% Sulfur; 29.2 MJ/kg | 0.52 g SO <sub>2</sub> /MJ    | 350 (0.3)                                                                                                                        | 350 (0.3) | NE        | NE        | NE        | --              |  |
| 3.5% Sulfur; 27.9 MJ/kg | 90% removal by FGD            | 130 (0.1)                                                                                                                        | 120 (0.1) | 210 (0.2) | 470 (0.4) | 110 (0.1) | --              |  |
| 7.0% Sulfur; 27.9 MJ/kg | 90% removal by FGD            | 150 (0.1)                                                                                                                        | 130 (0.1) | 340 (0.3) | 910 (0.8) | 110 (0.1) | --              |  |
| 0.8% Sulfur; 20.9 MJ/kg | 90% removal by FGD            | 120 (0.1)                                                                                                                        | 110 (0.1) | NE        | NE        | NE        | --              |  |
| 0.8% Sulfur; 25.6 MJ/kg | 90% removal by FGD            | 120 (0.1)                                                                                                                        | 110 (0.1) | NE        | NE        | NE        | --              |  |
| 0.8% Sulfur; 20.9 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | 110 (0.1)                                                                                                                        | 110 (0.1) | NE        | NE        | NE        | --              |  |
| 0.8% Sulfur; 25.6 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | 110 (0.1)                                                                                                                        | 110 (0.1) | NE        | NE        | NE        | --              |  |
| 2.3% Sulfur; 29.2 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | 360 (0.3)                                                                                                                        | 350 (0.3) | NE        | NE        | NE        | --              |  |
| 4.6% Sulfur; 29.2 MJ/kg | 0.22 g SO <sub>2</sub> /MJ    | 390 (0.4)                                                                                                                        | 360 (0.3) | NE        | NE        | NE        | --              |  |

NE - Not examined

Projected U.S. Energy Consumption in 1987 is  $110 \times 10^{15}$  J (BA-538).

Projected coal-fired generating capacity installed in 1983 through 1987 is 65,000 MW (65% operating factor).

\*Transporting western coal to a Midwest power plant - no FGD.

TABLE 4-8. PROJECTED SO<sub>2</sub> EMISSION CONTROL ENERGY PENALTIES--1997

| Projected SO <sub>2</sub> Emission Control Energy Penalty in 1997, 10 <sup>15</sup> J/yr<br>(% of Total U.S. Energy Consumption) |                               |            |            |            |            |           |                      |
|----------------------------------------------------------------------------------------------------------------------------------|-------------------------------|------------|------------|------------|------------|-----------|----------------------|
| Coal                                                                                                                             | SO <sub>2</sub> Control Level | Limestone  | Lime       | MgO        | W-L/A      | D-A       | Coal Transportation* |
| 3.5% Sulfur; 27.9 MJ/kg                                                                                                          | 0.52 g SO <sub>2</sub> /MJ    | 580 (0.4)  | 520 (0.4)  | 900 (0.7)  | 2000 (1.5) | 520 (0.4) | ---                  |
| 7.0% Sulfur; 27.9 MJ/kg                                                                                                          | 0.52 g SO <sub>2</sub> /MJ    | 710 (0.5)  | 650 (0.5)  | NE         | NE         | NE        | ---                  |
| 0.6% Sulfur; 20.9 MJ/kg                                                                                                          | Uncontrolled                  | ---        | ---        | ---        | ---        | ---       | 1100 (0.8)           |
| 0.8% Sulfur; 25.6 MJ/kg                                                                                                          | Uncontrolled                  | ---        | ---        | ---        | ---        | ---       | 900 (0.7)            |
| 2.3% Sulfur; 29.2 MJ/kg                                                                                                          | 0.52 g SO <sub>2</sub> /MJ    | 1680 (1.3) | 1680 (1.3) | NE         | NE         | NE        | ---                  |
| 3.5% Sulfur; 27.9 MJ/kg                                                                                                          | 90% removal by FGD            | 650 (0.5)  | 580 (0.4)  | 1030 (0.8) | 2260 (1.7) | 520 (0.4) | ---                  |
| 7.0% Sulfur; 27.9 MJ/kg                                                                                                          | 90% removal by FGD            | 710 (0.5)  | 650 (0.5)  | 1620 (1.2) | 4400 (3.4) | 520 (0.4) | ---                  |
| 0.8% Sulfur; 20.9 MJ/kg                                                                                                          | 90% removal by FGD            | 580 (0.4)  | 520 (0.4)  | NE         | NE         | NE        | ---                  |
| 0.8% Sulfur; 25.6 MJ/kg                                                                                                          | 90% removal by FGD            | 580 (0.4)  | 520 (0.4)  | NE         | NE         | NE        | ---                  |
| 0.8% Sulfur; 20.9 MJ/kg                                                                                                          | 0.22 g SO <sub>2</sub> /MJ    | 520 (0.4)  | 520 (0.4)  | NE         | NE         | NE        | ---                  |
| 0.8% Sulfur; 25.6 MJ/kg                                                                                                          | 0.22 g SO <sub>2</sub> /MJ    | 520 (0.4)  | 520 (0.4)  | NE         | NE         | NE        | ---                  |
| 2.3% Sulfur; 29.2 MJ/kg                                                                                                          | 0.22 g SO <sub>2</sub> /MJ    | 1740 (1.3) | 1680 (1.3) | NE         | NE         | NE        | ---                  |
| 4.6% Sulfur; 29.2 MJ/kg                                                                                                          | 0.22 g SO <sub>2</sub> /MJ    | 1870 (1.4) | 1740 (1.3) | NE         | NE         | NE        | ---                  |

NE - Not examined

Projected U.S. Energy Consumption in 1997 is  $130 \times 10^{15}$  J (BA-338).

Projected coal-fired generating capacity installed in 1983 through 1997 is 316,000 MW (65% operating factor).

\*Transporting western coal to a Midwest power plant - no FGD.

While the open literature contains many projections of future U.S. energy demands, these projections vary considerably. The following data are an average of several projections (BA-538)

|      | <u>Projected U.S. Energy Consumption</u>           |
|------|----------------------------------------------------|
| 1987 | $110 \times 10^{18}$ J ( $100 \times 10^{15}$ Btu) |
| 1997 | $130 \times 10^{18}$ J ( $120 \times 10^{15}$ Btu) |

These projections were used to calculate the "percent of Total U.S. Energy Consumption" data shown in Tables 4-7 and 4-8.

The data in Tables 4-7 and 4-8 indicated that in 1987 controlling SO<sub>2</sub> emissions from new sources, *i.e.*, those that come on-line after 1982, would increase U.S. energy consumption by an estimated 0.1 to 0.8 percent. In 1997 the increase in U.S. energy consumption is estimated to be 0.4 to 3.4 percent. The lower end of these ranges represents use of the nonregenerable FGD processes. The high end of the ranges represents combustion of 7 percent sulfur coal and removing 90 percent of the SO<sub>2</sub> by the Wellman-Lord/Allied FGD process. At the present time the limestone and lime are the most widely used FGD processes. This trend is anticipated to continue through 1997. Therefore, estimates of 0.1 percent and 0.4 percent for 1987 and 1997, respectively, are probably more accurate. For a given means of controlling SO<sub>2</sub> emissions, the data indicated that to achieve 90 percent SO<sub>2</sub> removal requires about 10 percent more energy than is required to meet the existing NSPS.

The SO<sub>2</sub> emission controls would also derate the projected 65,000 MW of new generating capacity installed in 1983-1987 by an estimated 2,300 MW. The projected 316,000 MW of new generating capacity installed in 1983-1997 would be derated by an estimated 11,000 MW.

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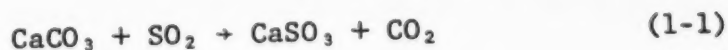
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APPENDIX A  
LIMESTONE FGD PROCESS

The limestone flue gas desulfurization process uses an aqueous slurry of limestone to absorb  $\text{SO}_2$  from flue gases. It is a nonregenerable desulfurization process since the  $\text{SO}_2$  sorbent is continuously consumed, being discharged from the process along with the absorbed  $\text{SO}_2$  as a calcium sulfite/sulfate sludge. Figure A-1 is a simplified flow scheme of the limestone FGD process selected for examination in this study.

Flue gas from the power plant air preheater enters a variable throat venturi scrubber. Liquor injected into the venturi removes approximately 99 percent of the flue gas particulate matter and a small amount of  $\text{SO}_2$ . Following particulate removal, the flue gas enters a two-bed, mobile bed absorber. Limestone slurry recirculated to this absorber can remove about 90 percent of the  $\text{SO}_2$  present in the flue gas. The overall chemistry of the  $\text{SO}_2$  removal process can be represented by the following two reactions:



The flue gas exiting the  $\text{SO}_2$  absorber is heated in an indirect steam reheater and compressed in an induced draft fan before entering the power plant stack for discharge to the atmosphere.

A portion of the recirculating liquor in the particulate scrubbing loop is directed to a lined settling pond where fly ash and calcium solids settle out. Clarified pond water is returned to the  $\text{SO}_2$  absorbers. Makeup limestone slurry for the  $\text{SO}_2$  absorbers is prepared on-site by crushing, grinding and slurring limestone.

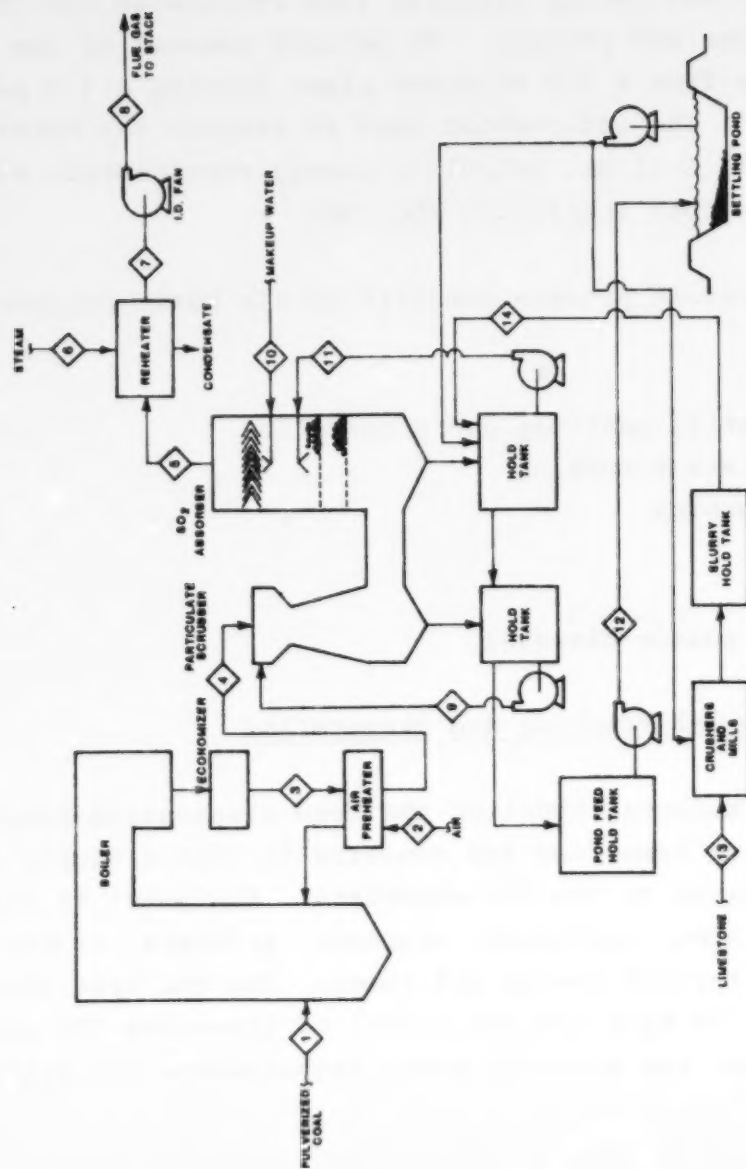


Figure A-1. Simplified flow scheme - limestone FGD process

## 1.1 Base Case - Limestone FGD Process

Material and energy balances were calculated for the base case limestone FGD process - 90 percent removal of the  $\text{SO}_2$  from the flue gas from a 500 MW power plant burning a 3.5 percent sulfur coal. The information used to prepare the material balance (see Table A-1) and calculate energy requirements was obtained from the open literature (MC-136).

The limestone process consists of six basic processing operations:

- Raw material handling and preparation
- Particulate scrubbing
- $\text{SO}_2$  scrubbing
- Reheat
- Fans
- Calcium solids disposal

### 1.1.1 Raw Material Handling and Preparation

The raw material handling and feed preparation processing operation takes raw limestone and converts it into a slurry for use as makeup reagent to the  $\text{SO}_2$  absorbers. Equipment in this area includes storage bins, conveyors, crushers, grinders, slurry tanks, a dust collection system and pumps. For the base case design in which 6.30 kg/s (50,000 lb/hr) of limestone (90 percent  $\text{CaCO}_3$ ) are handled, the electric power requirements are estimated at 790 kW.

TABLE A-1. BASE CASE MATERIAL BALANCE--LIMESTONE FGD PROCESS

| Stream No. | Stream Description                 | Rate |                    |                   | Temperature, °K |
|------------|------------------------------------|------|--------------------|-------------------|-----------------|
|            |                                    | kg/s | Nm <sup>3</sup> /s | m <sup>3</sup> /s |                 |
| 1          | Coal to Boiler                     | 47.3 |                    |                   |                 |
| 2          | Combustion Air to Boiler           | 570  | 430                |                   | 317             |
| 3          | Flue Gas to Air Preheater          | 555  | 421                |                   | 647             |
| 4          | Gas to Particulate Scrubber        | 611  | 464                |                   | 428             |
| 5          | Gas to Reheater                    | 637  | 518                |                   | 325             |
| 6          | Steam to Gas Reheater              | 8.88 |                    |                   | 517             |
| 7          | Gas to I.D. Fans                   | 637  | 518                |                   | 346             |
| 8          | Flue Gas to Atmosphere             | 637  | 518                |                   | 353             |
| 9          | Slurry to Particulate Scrubber     | 1372 |                    | 1.24              |                 |
| 10         | Makeup Water                       | 41.1 |                    | 0.04              |                 |
| 11         | Slurry to SO <sub>2</sub> Scrubber | 6048 |                    | 5.8               |                 |
| 12         | Slurry to Settling Pond            | 69.0 |                    | 0.06              |                 |
| 13         | Makeup Limestone                   | 6.3  |                    |                   |                 |
| 14         | Makeup Limestone Slurry            | 10.0 |                    | 0.006             |                 |

#### 1.1.2 Particulate Scrubbing

Included in the particulate scrubbing operation are variable throat venturi scrubbers, effluent hold tanks with agitators and scrubbing liquor recirculation pumps. To achieve approximately 99 percent removal of the flue gas particulate matter, the venturi scrubbers are operated at a liquid to gas ratio (based on exit flue gas conditions) of  $2 \text{ m}^3/1000 \text{ m}^3$  (15 gal/1000 acf). The electric power requirements for the recirculation pumps and agitators are estimated to be 920 kW.

#### 1.1.3 SO<sub>2</sub> Scrubbing

The SO<sub>2</sub> absorbers selected for the limestone FGD process are mobile bed absorbers. Hold tanks with agitators and scrubbing liquor recirculation pumps are also required. To effect 90 percent SO<sub>2</sub> removal in the base case design, a liquid to gas ratio (based on exit flue gas conditions) of approximately  $9.3 \text{ m}^3/1000 \text{ m}^3$  (70 gal/1000 acf) is required. The electric power requirements for SO<sub>2</sub> scrubbing are estimated to be 3,220 kW.

#### 1.1.4 Reheat

Scrubbed flue gas from a wet scrubbing process is normally reheated to obtain a stack exit temperature of about 353°K (175°F). This can be achieved by combustion of an auxiliary fuel with direct injection of the hot combustion gases into the scrubbed flue gas or by indirect heating with steam. The latter method was selected because the reheat steam can be obtained from the power plant boiler. Since some reheat is provided by the induced draft fans downstream of the reheater,

approximately 21°K (38°F) of additional reheat are required. For the base base, the reheat energy requirements are estimated to be 15.6 MJ/s ( $53.2 \times 10^6$  Btu/hr). At an available steam heat content of 1.75 MJ/kg (755 Btu/lb), the steam requirements for the reheater are 8.88 kg/s (70,400 lb/hr).

#### 1.1.5 Fans

Induced draft fans located downstream of the flue gas reheater are used to overcome the pressure drop of the flue gas as it passes through the limestone FGD process. For the base case design, which has a pressure drop of 6.5 kPa (26 in. H<sub>2</sub>O), the electric power requirements for the fans are estimated to be 6,150 kW.

#### 1.1 6 Calcium Solids Disposal

This process operation includes a pond feed tank with agitator, a lined settling pond and pumps for transporting the fly ash/calcium solids slurry to the settling pond and returning pond water to the scrubbing system. Since the calcium solids represent about 60 percent of the total solids directed to the settling pond, the energy requirements for solids disposal are prorated using this factor. For the base case design in which 2.58 kg/s (10.3 ton/hr) of SO<sub>2</sub> are removed, the electric power requirements for disposal of the resulting calcium solid are estimated at 100 kW.

#### 1.1.7 Utilities and Services

Utilities and services such as instrument air, lighting, heating, cooling, etc., are required for the limestone FGD facilities. For the base case design, the electric power requirements for utilities and services are estimated at 60 kW.

### 1.1.8 Base Case Summary

The electricity and steam requirements for the base case limestone FGD process are summarized in Table A-2. As shown by the data in this table, a 500 MW power plant burning a 3.5 percent sulfur coal without any SO<sub>2</sub> emission controls would require an energy input of 1.32 GJ/s ( $4.50 \times 10^9$  Btu/hr). Reducing the SO<sub>2</sub> emissions from this plant by 90 percent with a limestone FGD system would derate the power plant by 18 MW. This assumes that all of the energy requirements of the FGD system are obtained from the power plant. The uncontrolled plant net heat rate is 2,640 J/kW-s (9,000 Btu/kW-hr). Since the net heat rate for the controlled plant is 2,740 J/kW-s (9,350 Btu/kW-hr), the energy penalty of the SO<sub>2</sub> control system is 100 J/kW-s (350 Btu/kW-hr).

A percentage breakdown of the energy requirements for the base case limestone FGD process are shown below.

|                                       |      |
|---------------------------------------|------|
| Raw material handling and preparation | - 4% |
| Particulate scrubbing                 | - 5% |
| SO <sub>2</sub> scrubbing             | -18% |
| Reheat                                | -37% |
| Fans                                  | -34% |
| Calcium solids disposal               | -<1% |
| Utilities and services                | -<1% |

The particulate scrubbers, reheaters and fans account for about 75 percent of the base case limestone system energy requirements. Since the energy requirements for these process operations depend essentially only on the flue gas flow rate, a very large portion of the total system energy requirements are insensitive to the SO<sub>2</sub> concentration in the flue gas. This indicates that for a given power plant capacity, the energy requirements for the SO<sub>2</sub>

TABLE A-2. SUMMARY OF BASE CASE ENERGY REQUIREMENTS - LIMESTONE FGD PROCESS

| Basis: 500 MW power plant burning 3.5% sulfur coal<br>90% SO <sub>2</sub> removal by limestone FGD process |                                       |                     |                         |
|------------------------------------------------------------------------------------------------------------|---------------------------------------|---------------------|-------------------------|
|                                                                                                            | Electricity and<br>Steam Requirements | x Conversion Factor | = Input to Boiler, MJ/s |
| Raw Material Handling<br>and Preparation                                                                   | 790 kW                                | 2,640 J/kW-s        | 2.1                     |
| Particulate Scrubbing                                                                                      | 920 kW                                | 2,640 J/kW-s        | 2.4                     |
| SO <sub>2</sub> Scrubbing                                                                                  | 3,220 kW                              | 2,640 J/kW-s        | 8.5                     |
| Reheat                                                                                                     | 8.88 kg stm/s                         | 1.99 MJ/kg stm*     | 17.7                    |
| Fans                                                                                                       | 6,150 kW                              | 2,640 J/kW-s        | 16.2                    |
| Calcium Solids Disposal                                                                                    | 100 kW                                | 2,640 J/kW-s        | 0.3                     |
| Utilities and Services                                                                                     | 60 kW                                 | 2,640 J/kW-s        | 0.2                     |
| TOTAL = 47.4                                                                                               |                                       |                     |                         |
| Energy Input to Boiler                                                                                     | 1,320 MJ/s                            |                     |                         |
| Less SO <sub>2</sub> Control System                                                                        | 47 MJ/s                               |                     |                         |
| Net Available Energy                                                                                       | 1,273 MJ/s                            |                     |                         |
| Uncontrolled Plant Net Heat Rate                                                                           | 2,640 J/kW-s                          |                     |                         |
| Net Power Plant Capacity                                                                                   | 482,000 kW                            |                     |                         |
| Controlled Plant Net Heat Rate                                                                             | 2,740 J/kW-s                          |                     |                         |

\*Based on an 88 percent boiler energy efficiency

emission control systems which use the limestone FGD process should be approximately equal. Differences which do occur result from the dependence of the raw material handling and preparation and SO<sub>2</sub> scrubbing operations on flue gas SO<sub>2</sub> concentration and SO<sub>2</sub> removal level.

## 1.2 Base Case Extrapolation

The electricity and steam requirements for all of the SO<sub>2</sub> control cases which use the limestone FGD process can be extrapolated from the base case data. The electric power requirements for the raw material handling and preparation, and calcium solids disposal operations are proportional to the amount of SO<sub>2</sub> removed. For particulate scrubbing, reheat, and utilities and services, the electric power and steam requirements can be related to the flue gas flow rate exiting the power plant air preheater. The following extrapolation factors were identified for these five segments of the limestone FGD process:

|                                       |                                       |
|---------------------------------------|---------------------------------------|
| Raw material handling and preparation | - 306 kW/(kg SO <sub>2</sub> rem./s)  |
| Particulate scrubbing                 | - 1.98 kW/(Nm <sup>3</sup> /s)        |
| Reheat                                | - 33.5 kJ/Nm <sup>3</sup>             |
| Calcium solids disposal               | - 38.7 kW/(kg SO <sub>2</sub> rem./s) |
| Utilities and services                | - 0.13 kW/(Nm <sup>3</sup> /s)        |

The electric power requirements for the SO<sub>2</sub> scrubbers and fans are dependent on the SO<sub>2</sub> concentration in the flue gas and the desired SO<sub>2</sub> removal level. Methods of calculating the power requirements for these operations are described below.

### 1.2.1 SO<sub>2</sub> Scrubbing

Variables which determine the amount of SO<sub>2</sub> that can

be removed in a mobile bed absorber include:

- the liquid to gas ratio,
- the gas velocity,
- the scrubbing liquor pH,
- the inlet SO<sub>2</sub> concentration,
- the height of the bed, number of beds, and diameter of packing, and
- the chloride and magnesium ion concentration in the scrubbing liquor.

Based on test data for limestone wet scrubbing using a turbulent bed contactor (a type of mobile bed) at the TVA Shawnee plant, Bechtel Corporation developed the following semi-empirical correlation relating the above variables to SO<sub>2</sub> removal.

$$\eta_{SO_2} = 1 - \exp[-2.05 \times 10^{-4} \times (L/G)^{0.81} \times v^{0.36} \exp[4.3 \times 10^{-3} \times v \times (h/d + N) + 0.81 \times pH_i + 7.9 \times 10^{-5} \times (Mg) - 1.7 \times 10^{-4} \times Y_i + 1.3 \times 10^{-5} \times (Cl)]] \quad (1-3)$$

where  $\eta_{SO_2}$  = fraction of SO<sub>2</sub> removal  
 L/G = liquid to gas ratio, gal/1000 cf at outlet conditions  
 v = gas velocity, ft/s  
 h = height of bed, in  
 d = diameter of packing, in  
 N = number of beds  
 pH<sub>i</sub> = inlet scrubbing liquor pH  
 Y<sub>i</sub> = inlet SO<sub>2</sub> concentration, ppm  
 Cl = inlet scrubbing liquor chloride concentration, ppm  
 Mg = effective inlet scrubbing liquor magnesium concentration, ppm

The following values, which are typical of those used in the development of the Bechtel correlation, were assumed for use in Equation (1-3):

|                 |             |
|-----------------|-------------|
| v               | = 10 ft/s   |
| h               | = 15 in.    |
| d               | = 1.5 in.   |
| N               | = 2         |
| pH <sub>i</sub> | = 6.0       |
| Cl              | = 3,000 ppm |
| Mg              | = 0 ppm     |

Substituting these values into Equation (1-3) gives

$$\eta_{SO_2} = 1 - \exp[-4.7 \times 10^{-4} \times (L/G)^{0.81} \exp[5.4 - 1.7 \times 10^{-4} \times Y_1]] \quad (1-4)$$

Equation 1-4 was developed from data which included inlet SO<sub>2</sub> concentrations of 1500-4500 ppm. Although use of low sulfur western coals produces inlet SO<sub>2</sub> concentrations of about 500 ppm, it is felt that Equation 1-4 will give reasonable estimates of L/G's for these inlet SO<sub>2</sub> concentrations. Since the power requirements for SO<sub>2</sub> scrubbing are directly related to the scrubbing liquor flow rate, knowledge of the required L/G and the flue gas flow rate permits calculation of the electric power requirements. Table A-3 lists the L/G's calculated from Equation (1-4).

#### 1.2.2 Fans

Flue gas flow rate and pressure drop are the two major variables which affect the energy requirements of fans. For the

low pressure drops which fans must overcome, the following equation can be used to calculate power requirements:

$$\text{power required, kW} = \frac{Q \times \Delta P}{e} \quad (1-5)$$

where  $Q$  = flue gas flow rate,  $\text{m}^3/\text{s}$

$\Delta P$  = pressure drop, kPa

$e = 0.690$  = energy conversion efficiency of fan and motor

Table A-3 lists the system pressure drops for the control cases examined. These pressure drops were calculated from the base case data and a relationship developed by Bechtel for the dependence of pressure drop on L/G in a turbulent contact absorber.

TABLE A-3. OPERATING PARAMETERS - LIMESTONE FGD PROCESS

| SO <sub>2</sub> Control Level | Coal                    | SO <sub>2</sub> Scrubber L/G,<br>m <sup>3</sup> /1000 m <sup>3</sup> | Total System ΔP, kPa |
|-------------------------------|-------------------------|----------------------------------------------------------------------|----------------------|
| 0.52 g SO <sub>2</sub> /MJ    | 3.5% Sulfur; 27.9 MJ/kg | 5.2                                                                  | 6.4                  |
| 0.52 g SO <sub>2</sub> /MJ    | 7.0% Sulfur; 27.9 MJ/kg | 13                                                                   | 6.6                  |
| 0.52 g SO <sub>2</sub> /MJ    | 2.2% Sulfur; 29.2 MJ/kg | 2.8                                                                  | 6.3                  |
| 90% removal by FGD            | 3.5% Sulfur; 27.9 MJ/kg | 9.3                                                                  | 6.5                  |
| 90% removal by FGD            | 7.0% Sulfur; 27.9 MJ/kg | 14                                                                   | 6.6                  |
| 90% removal by FGD            | 0.8% Sulfur; 20.9 MJ/kg | 6.8                                                                  | 6.4                  |
| 90% removal by FGD            | 0.8% Sulfur; 25.6 MJ/kg | 6.8                                                                  | 6.4                  |
| 0.22 g SO <sub>2</sub> /MJ    | 0.8% Sulfur; 20.9 MJ/kg | 2.7                                                                  | 6.3                  |
| 0.22 g SO <sub>2</sub> /MJ    | 0.8% Sulfur; 25.6 MJ/kg | 2.7                                                                  | 6.3                  |
| 0.22 g SO <sub>2</sub> /MJ    | 2.2% Sulfur; 29.2 MJ/kg | 6.3                                                                  | 6.4                  |
| 0.22 g SO <sub>2</sub> /MJ    | 4.4% Sulfur; 29.2 MJ/kg | 12                                                                   | 6.5                  |

APPENDIX B  
LIME FGD PROCESS

## 1.0

### LIME FGD PROCESS

The lime flue gas desulfurization process is very similar to the limestone FGD process. The major difference is the source of alkalinity used to absorb  $\text{SO}_2$ . As the name of the systems imply, the lime process uses a lime slurry while the limestone process uses a limestone slurry. The overall chemistry of the lime process can be represented by the following reactions.

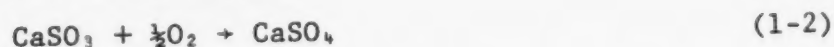
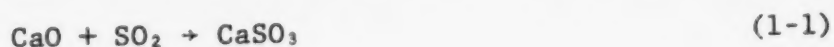


Figure B-1 is a simplified flow scheme of the lime FGD process selected for examination in this study.

## 1.1

### Base Case - Lime FGD Process

Material and energy balances were calculated for the base case lime FGD process--90 percent removal of the  $\text{SO}_2$  from the flue gas from a 500 MW power plant burning a 3.5 percent sulfur coal. The information used to prepare the material balance (see Table B-1) and calculate energy requirements was obtained from the open literature (MC-136).

There are six general process operations in the lime FGD process:

- Raw material handling and preparation
- Particulate scrubbing
- $\text{SO}_2$  scrubbing
- Reheat
- Fans
- Calcium solids disposal

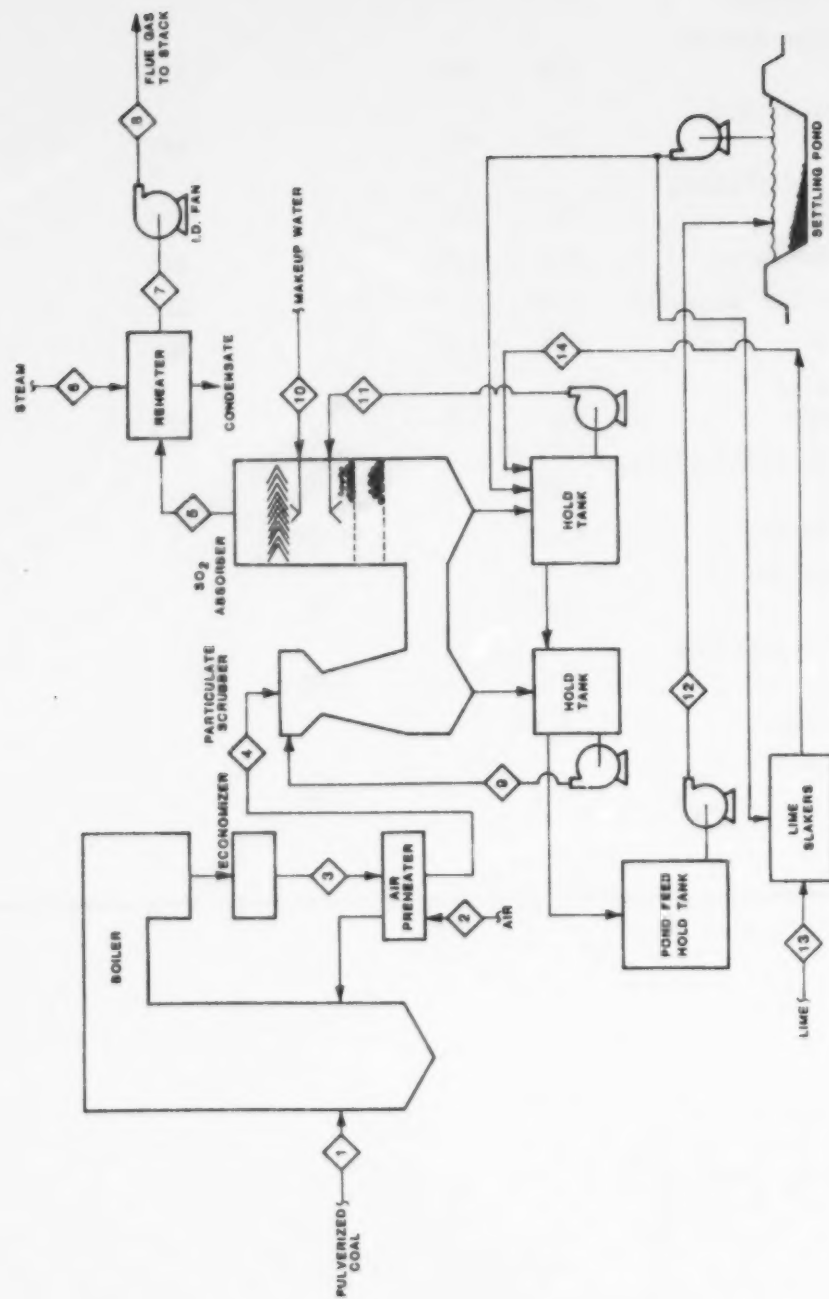


Figure B-1. Simplified flow scheme - lime FGD process

TABLE B-1. BASE CASE MATERIAL BALANCE--LIME FGD PROCESS

| Stream No. | Stream Description                 | Rate |                    |                   | Temperature, °K |
|------------|------------------------------------|------|--------------------|-------------------|-----------------|
|            |                                    | kg/s | Nm <sup>3</sup> /s | m <sup>3</sup> /s |                 |
| 1          | Coal to Boiler                     | 47.3 |                    |                   |                 |
| 2          | Combustion Air to Boiler           | 570  | 430                |                   | 317             |
| 3          | Flue Gas to Air Preheater          | 555  | 421                |                   | 647             |
| 4          | Gas to Particulate Scrubber        | 611  | 464                |                   | 428             |
| 5          | Gas to Reheater                    | 637  | 518                |                   | 325             |
| 6          | Steam to Gas Reheater              | 8.88 |                    |                   | 517             |
| 7          | Gas to I.D. Fans                   | 637  | 518                |                   | 346             |
| 8          | Flue Gas to Atmosphere             | 637  | 518                |                   | 353             |
| 9          | Slurry to Particulate Scrubber     | 1372 |                    | 1.24              |                 |
| 10         | Makeup Water                       | 41.1 |                    | 0.04              |                 |
| 11         | Slurry to SO <sub>2</sub> Scrubber | 6048 |                    | 5.8               |                 |
| 12         | Slurry to Settling Pond            | 69.0 |                    | 0.06              |                 |
| 13         | Makeup Lime                        | 2.9  |                    |                   |                 |
| 14         | Makeup Lime Slurry                 | 25.3 |                    | 0.02              |                 |

The particulate scrubbing and reheat operations are identical to those in the limestone process. For the base case design, the electric power requirements for particulate scrubbing are estimated to be 920 kW. The steam requirements for the reheater are estimated to be 8.88 kg/s (70,400 lb/hr).

#### 1.1.1 Raw Material Handling and Preparation

The raw material handling and feed preparation operation is designed to receive pebble lime and prepare a 25 percent solids slurry for use as makeup reagent for the SO<sub>2</sub> absorbers. Major equipment items include conveyors, storage bins, vibrators, slakers, a slurry surge tank and pumps. For the base case design in which 2.93 kg/s (23,200 lb/hr) of lime (95 percent CaO) are handled, the electric power requirements are estimated to be 80 kW.

#### 1.1.2 SO<sub>2</sub> Scrubbing

The SO<sub>2</sub> absorbers selected for the lime FGD process are mobile bed absorbers. Hold tanks with agitators and scrubbing liquor recirculation pumps are also required. To effect 90 percent SO<sub>2</sub> removal in the base case design, a liquid to gas ratio (based on exit flue gas conditions) of approximately 6.7 m<sup>3</sup>/1000 m<sup>3</sup> (50 gal/1000 acf) is required. The electric power requirements for SO<sub>2</sub> scrubbing are estimated to be 2,300 kW.

#### 1.1.3 Fans

Induced draft fans located downstream of the reheater are used to overcome the pressure drop of the flue gas as it passes through the lime FGD process. For the base case design

which has a pressure drop of 6.4 kPa (26 in. H<sub>2</sub>O), the electric power requirements for the fans are estimated to be 6,100 kW.

#### 1.1.4 Calcium Solids Disposal

The calcium solids produced in the SO<sub>2</sub> absorber are disposed of in lined settling ponds. For the base case design in which 2.58 kg/s (10.3 ton/hr) of SO<sub>2</sub> are removed, the electric power requirements for disposal of the resulting calcium solids are estimated to be 60 kW.

#### 1.1.5 Utilities and Services

The utilities and services required by the lime FGD process are similar to those for the limestone process. For the base case design, the electric power requirements for utilities and services are estimated to be 60 kW.

#### 1.1.6 Base Case Summary

The electricity and steam requirements for the base case lime FGD process are summarized in Table B-2. As before, a 500 MW power plant burning a 3.5 percent sulfur coal without any SO<sub>2</sub> emission controls would require an energy input of 1.32 GJ/s ( $4.50 \times 10^9$  Btu/hr). Reducing the SO<sub>2</sub> emissions from this plant by 90 percent with a lime FGD system would derate the power plant by 16 MW. This assumes that all energy requirements of the FGD system are obtained from the power plant. The uncontrolled plant net heat rate is 2,640 J/kW-s (9,000 Btu/kW-hr). Since the net heat rate for the controlled plant is 2,730 J/kW-s (9,320 Btu/kW-hr), the energy penalty of the SO<sub>2</sub> control system is 90 J/kW-s (320 Btu/kW-hr).

TABLE B-2. SUMMARY OF BASE CASE ENERGY REQUIREMENTS - LIME FGD PROCESS

| Basis: 500 MW power plant burning 3.5% sulfur coal<br>90% SO <sub>2</sub> removal via lime FGD process |                                       |                     |                                              |
|--------------------------------------------------------------------------------------------------------|---------------------------------------|---------------------|----------------------------------------------|
| Area                                                                                                   | Electricity and<br>Steam Requirements | x Conversion Factor | = Equivalent Energy<br>Input to Boiler, MJ/s |
| Raw Material Handling<br>and Preparation                                                               | 80 kW                                 | 2,640 J/kW-s        | 0.2                                          |
| Particulate Scrubbing                                                                                  | 920 kW                                | 2,640 J/kW-s        | 2.4                                          |
| SO <sub>2</sub> Scrubbing                                                                              | 2,300 kW                              | 2,640 J/kW-s        | 6.1                                          |
| Reheat                                                                                                 | 8.88 kg stm/s                         | 1.99 MJ/kg stm*     | 17.7                                         |
| Fans                                                                                                   | 6,100 kW                              | 2,640 J/kW-s        | 16.1                                         |
| Calcium Solids Disposal                                                                                | 60 kW                                 | 2,640 J/kW-s        | 0.2                                          |
| Utilities and Services                                                                                 | 60 kW                                 | 2,640 J/kW-s        | 0.2                                          |
|                                                                                                        |                                       |                     | TOTAL = 42.9                                 |
| Energy Input to Boiler                                                                                 | 1,320 MJ/s                            |                     |                                              |
| Less SO <sub>2</sub> Control System                                                                    | 43 MJ/s                               |                     |                                              |
| Net Available Energy                                                                                   | 1,277 MJ/s                            |                     |                                              |
| Uncontrolled Plant Net Heat Rate                                                                       | 2,640 J/kW-s                          |                     |                                              |
| Net Power Plant Capacity                                                                               | 484,000 kW                            |                     |                                              |
| Controlled Plant Net Heat Rate                                                                         | 2,730 J/kW-s                          |                     |                                              |

\*Based on an 88 percent boiler energy efficiency

A percentage breakdown of the energy requirements for the base case lime FGD process are shown below:

|                                       |       |
|---------------------------------------|-------|
| Raw material handling and preparation | - <1% |
| Particulate scrubbing                 | - 6%  |
| SO <sub>2</sub> scrubbing             | - 14% |
| Reheat                                | - 41% |
| Fans                                  | - 38% |
| Calcium solids disposal               | - <1% |
| Utilities and services                | - <1% |

The particulate scrubbers, reheaters and fans account for about 80 percent of the lime system energy requirements. Since the energy requirements for these operations depend essentially only on the flue gas flow rate, a very large portion of the total system energy requirements are insensitive to the SO<sub>2</sub> concentration in the flue gas. This indicates that for a given power plant capacity, the energy requirements for the SO<sub>2</sub> emission control systems which use the lime FGD process should be approximately equal. Differences which do occur result from the dependence of the raw material handling and preparation and SO<sub>2</sub> scrubbing operations on flue gas SO<sub>2</sub> concentration and SO<sub>2</sub> removal level.

## 1.2 Base Case Extrapolation

The electricity and steam requirements for all of the SO<sub>2</sub> control cases which use the lime FGD process can be extrapolated from the base case data. The electric power requirements for the raw material handling and preparation, and calcium solids disposal operations are proportional to the amount of SO<sub>2</sub> removed. For particulate scrubbing, reheat, and utilities and services, the electric power and steam requirements can be

related to the flue gas flow rate exiting the power plant air preheater. The following extrapolation factors were identified for these five segments of the lime FGD process:

|                                       |                                       |
|---------------------------------------|---------------------------------------|
| Raw material handling and preparation | - 30.9 kW/(kg SO <sub>2</sub> rem./s) |
| Particulate scrubbing                 | - 1.98 kW/(Nm <sup>3</sup> /s)        |
| Reheat                                | - 33.5 kJ/Nm <sup>3</sup>             |
| Calcium solids disposal               | - 38.7 kW/(kg SO <sub>2</sub> rem./s) |
| Utilities and services                | - 0.13 kW/(Nm <sup>3</sup> /s)        |

The power requirements for the SO<sub>2</sub> scrubbers and fans are dependent on the SO<sub>2</sub> concentration in the flue gas and the desired SO<sub>2</sub> removal level. Methods of calculating the power requirements for these operations are described below.

#### 1.2.1 SO<sub>2</sub> Scrubbing

Bechtel Corporation developed an equation for the lime process that is similar in form to that used for calculating L/G's for the SO<sub>2</sub> absorber in the limestone process.

$$\eta_{\text{SO}_2} = 1 - \exp[-0.001 \times (L/G)^{1.12} \times v^{0.65} \exp[0.0039 \times v \times (h/d + N) + 0.18 \times \text{pH}_1 + 1.5 \times 10^{-4} \times (\text{Mg}) - 2.2 \times 10^{-4} \times Y_1]] \quad (1-3)$$

where  $\eta_{\text{SO}_2}$  = fraction of SO<sub>2</sub> removal  
 L/G = liquid to gas ratio, gal/1000 cf at outlet conditions  
 v = gas velocity, ft/s  
 h = height of bed, in

$d$  = diameter of packing, in  
 $N$  = number of beds  
 $pH_i$  = inlet scrubbing liquor pH  
 $Y_i$  = inlet  $SO_2$  concentration, ppm  
 $Mg$  = effective inlet scrubbing liquor magnesium concentration, ppm

The following values which are typical of those used in the development of the Bechtel correlation, were assumed for use in Equation (1-3):

$v$  = 12.5 ft/s  
 $h$  = 15 in.  
 $d$  = 1.5 in.  
 $N$  = 2  
 $pH_i$  = 8.0  
 $C_l$  = 3,000 ppm  
 $Mg$  = 0 ppm

Substituting these values into Equation (1-3) gives

$$\eta_{SO_2} = 1 - \exp[-5.2 \times 10^{-3} \times (L/G)^{1.12} \exp[2.0 - 2.2 \times 10^{-4} \times Y_i]] \quad (1-4)$$

Equation 1-4 was developed from data which included inlet  $SO_2$  concentrations of 2000-4000 ppm. Although some coals used in this study produce inlet  $SO_2$  concentrations outside this range, it is felt that Equation 1-4 will give reasonable estimates of L/G's for these inlet  $SO_2$  concentrations. Since the power requirements for  $SO_2$  scrubbing are directly related to the scrubbing liquor flow rate, knowledge of the required L/G and

the flue gas flow rate permits calculation of the electric power requirements. Table B-3 lists the L/G's calculated from Equation (1-4).

#### 1.2.2 Fans

The equation for calculating the power requirements for induced draft fans is given by Equation 1-5 in Appendix A. The pressure drops for use in Equation 1-5 are given in Table B-3 for the lime FGD control cases.

TABLE B-3. OPERATING PARAMETERS - LIME FGD PROCESS

| SO <sub>2</sub> Control Level | Coal                    | SO <sub>2</sub> Scrubber L/G,<br>m <sup>3</sup> /1000 m <sup>3</sup> | Total System ΔP, kPa |
|-------------------------------|-------------------------|----------------------------------------------------------------------|----------------------|
| 0.52 g SO <sub>2</sub> /MJ    | 3.5% Sulfur; 27 MJ/kg   | 4.7                                                                  | 6.4                  |
| 0.52 g SO <sub>2</sub> /MJ    | 7.0% Sulfur; 27 MJ/kg   | 10                                                                   | 6.5                  |
| 0.52 g SO <sub>2</sub> /MJ    | 3.5% Sulfur; 29.2 MJ/kg | 2.6                                                                  | 6.3                  |
| 90% removal by FGD            | 3.5% Sulfur; 27.9 MJ/kg | 6.7                                                                  | 6.4                  |
| 90% removal by FGD            | 7.0% Sulfur; 27.9 MJ/kg | 10                                                                   | 6.5                  |
| 90% removal by FGD            | 0.8% Sulfur; 20.9 MJ/kg | 4.7                                                                  | 6.4                  |
| 90% removal by FGD            | 0.8% Sulfur; 25.6 MJ/kg | 4.7                                                                  | 6.4                  |
| 0.22 g SO <sub>2</sub> /MJ    | 0.8% Sulfur; 20.9 MJ/kg | 2.6                                                                  | 6.3                  |
| 0.22 g SO <sub>2</sub> /MJ    | 0.8% Sulfur; 25.6 MJ/kg | 2.0                                                                  | 6.3                  |
| 0.22 g SO <sub>2</sub> /MJ    | 2.2% Sulfur; 29.2 MJ/kg | 4.7                                                                  | 6.4                  |
| 0.22 g SO <sub>2</sub> /MJ    | 4.4% Sulfur; 29.2 MJ/kg | 8.7                                                                  | 6.5                  |

APPENDIX C  
MAGNESIA SLURRY FGD PROCESS

The magnesia slurry (MgO) flue gas desulfurization process uses an aqueous slurry of MgO to absorb SO<sub>2</sub> from flue gases. The process is termed regenerable since the scrubbing slurry is thermal regenerated to produce MgO and SO<sub>2</sub>. The MgO is recycled to the scrubbing system while the SO<sub>2</sub> is converted into sulfuric acid. Figure C-1 is a simplified flow scheme of the MgO slurry FGD process selected for examination in this study.

Flue gas from the power plant air preheater first enters a variable throat venturi scrubber. A fly ash slurry is injected into this venturi to remove particulates and chlorides. The flue gas next enters a second venturi wherein SO<sub>2</sub> is absorbed by injection of magnesia slurry. The overall chemistry of the SO<sub>2</sub> absorption step can be represented by the following reaction.



Flue gas exiting the second venturi is heated in an indirect steam reheater and compressed in an induced draft fan prior to entering the power plant stack for discharge to the atmosphere.

A portion of the recirculating SO<sub>2</sub> absorber scrubbing liquor is continuously removed and directed to the regeneration facilities. Here, MgSO<sub>3</sub> solids are separated from the liquor and thermally regenerated in an oil-fired fluid bed calciner. The calcination reaction is the reverse of Reaction 1-1. The regenerated MgO is recycled to the scrubber, while the SO<sub>2</sub> is sent to a conventional contact sulfuric acid plant. Makeup



magnesia slurry is prepared on-site by slurrying recycle and fresh MgO.

### 1.1 Base Case-MgO FGD Process

Material and energy balances were calculated for the base case MgO FGD process - 90 percent removal of the SO<sub>2</sub> from the flue gas from a 500 MW power plant burning a 3.5 percent sulfur coal. The information used to prepare the material balance (see Table C-1) and calculate energy requirements was obtained from the open literature (MC-136).

There are nine general operations in the MgO FGD process:

- . Raw material handling and preparation
- . Particulate/Chloride Removal
- . SO<sub>2</sub> scrubbing
- . Reheat
- . Fans
- . Slurry processing
- . Cake drying
- . MgSO<sub>3</sub> calcining
- . Sulfuric acid production

#### 1.1.1 Raw Material Handling and Preparation

The raw material handling and feed preparation operation includes equipment for receiving coke and fresh MgO and for storing, conveying and slurrying fresh and recycle MgO. The equipment is designed to handle 0.038 kg/s (300 lb/hr) of fresh MgO (98% purity), 2.09 kg/s (16,600 lb/hr) of recycle MgO

TABLE C-1. BASE CASE MATERIAL BALANCE - MAGNESIA SLURRY FGD PROCESS

| Stream No. | Stream Description                 | Rate |                    | Temperature, °K |
|------------|------------------------------------|------|--------------------|-----------------|
|            |                                    | kg/s | Nm <sup>3</sup> /s |                 |
| 1          | Coal to Boiler                     | 47.3 |                    |                 |
| 2          | Combustion Air to Boiler           | 570  | 430                | 317             |
| 3          | Gas to Air Preheater               | 555  | 421                | 647             |
| 4          | Gas to Particulate Scrubber        | 611  | 464                | 428             |
| 5          | Gas to SO <sub>2</sub> Absorber    | 639  | 500                | 326             |
| 6          | Gas to Reheater                    | 650  | 511                | 326             |
| 7          | Steam to Reheater                  | 7.44 |                    | 517             |
| 8          | Gas to I.D. Fan                    | 650  | 511                | 344             |
| 9          | Gas to Atmosphere                  | 650  | 511                | 352             |
| 10         | Slurry to Particulate Scrubber     | 1231 | 1.20               |                 |
| 11         | Slurry to SO <sub>2</sub> Absorber | 1737 | 1.60               |                 |
| 12         | Slurry to Slurry Processing        | 137  | 0.13               |                 |
| 13         | Oil to Calciner                    | 0.41 |                    |                 |
| 14         | Oil to Dryer                       | 0.37 |                    |                 |
| 15         | Sulfuric Acid                      | 16.2 | 0.002              |                 |
| 16         | Acid Plant Tail Gas                | 13.0 | 1.31               | 344             |

and 0.0275 kg/s (218 lb/hr) of coke. Based on these flow rates, the electric power requirements are estimated to be 180 kW.

#### 1.1.2 Particulate/Chloride Removal

Included in the particulate/chloride scrubbing operation are variable throat venturi scrubbers, effluent surge tanks and recirculating slurry, makeup water and slurry disposal pumps. The venturi scrubbers operate at a gas phase pressure drop of 2.1 kPa (8.5 in. H<sub>2</sub>O) and a liquid to gas ratio (based on exit flue gas conditions) of 2 m<sup>3</sup>/1000 m<sup>3</sup> (15 gal/1000 acf). For the base case design, the electric power requirements for particulate scrubbing are estimated to be 1,090 kW.

#### 1.1.3 SO<sub>2</sub> Scrubbing

The SO<sub>2</sub> scrubbing operation includes variable throat venturi scrubbers and magnesia slurry recirculation pumps. The scrubbers operate at an L/G (based on exit flue gas conditions) of 2.7 m<sup>3</sup>/1000 m<sup>3</sup> (20 gal/1000 acf) and a gas phase pressure drop of 1.1 kPa (4.5 in. H<sub>2</sub>O). For the base case MgO process, the electric power requirements for the SO<sub>2</sub> scrubbing operation are estimated to be 910 kW.

#### 1.1.4 Reheat

As for the limestone and lime FGD processes, indirect steam reheaters are used to heat the scrubbed flue gas prior to discharge to the atmosphere. For the base case design which requires approximately 18°K (33°F) of reheat, the reheater heat duty is estimated at 13.9 MJ/s (47.4 x 10<sup>6</sup> Btu/hr). A portion of this heat duty, 0.85 MJ/s (2.9 x 10<sup>6</sup> Btu/hr), is assumed to be provided by steam generated in the MgSO<sub>3</sub> calcining area.

Thus, the power plant boiler must provide only 13.0 MJ/s (44.5 Btu/hr). At an available steam heat content of 1.75 MJ/kg (755 Btu/lb), the steam rate to the reheater is 7.44 kg/s (59,000 lb/hr).

#### 1.1.5 Fans

To overcome the pressure drop of the flue gas as it passes through the MgO FGD process, induced draft fans are located downstream of the flue gas reheater. For the base case design which has a pressure drop of 5.7 kPa (23 in. H<sub>2</sub>O), the electric power requirements for the fans are estimated to be 5,420 kW.

#### 1.1.6 Slurry Processing

The slurry processing operation receives a slipstream of the recirculating liquor from the SO<sub>2</sub> absorbers. This liquor, which contains MgSO<sub>3</sub>·6H<sub>2</sub>O solids, is first screened to remove some of the water and then heated indirectly by steam to convert the MgSO<sub>3</sub>·6H<sub>2</sub>O to MgSO<sub>3</sub>·3H<sub>2</sub>O. The resulting slurry is centrifuged, with the centrifuge cake being sent to the cake drying operation while the centrate is returned to the SO<sub>2</sub> absorbers. Based on the removal of 2.58 kg/s (10.3 tons/hr) of SO<sub>2</sub>, the electric power requirements for the slurry processing operation are estimated at 380 kW. The heat requirements are obtained from steam produced in the waste heat boiler in the MgSO<sub>3</sub> calcination operation.

#### 1.1.7 Cake Drying

Included in the cake drying operation are an oil-fired fluid bed dryer, an air blower, a cyclone, a fabric filter, an

induced draft fan, conveyors, and a  $\text{MgSO}_3$  storage silo. The centrifuge cake from slurry processing is thermally dried in the fluid bed dryer by hot gases produced from the combustion of fuel oil. The dryer offgases are treated for particulate removal before being discharged to the atmosphere through the power plant flue gas stack. For treating the  $\text{MgSO}_3$  produced by removing 2.58 kg/s (10.3 ton/hr) of  $\text{SO}_2$ , the electric power requirements for the cake drying operation are estimated at 410 kW. The heat rate for the fluid bed dryer is estimated at 16.0 MJ/s ( $54.4 \times 10^6$  Btu/hr). Based on use of No. 6 fuel oil with a heating value of 41.5 GJ/m<sup>3</sup> (149,000 Btu/gal), the fuel oil requirements are 0.000384 m<sup>3</sup>/s (365 gal/hr).

#### 1.1.8 $\text{MgSO}_3$ Calcining

$\text{MgSO}_3$  from the cake drying operation is calcined in an oil-fired fluid bed calciner to produce MgO for recycle to the  $\text{SO}_2$  scrubbers and  $\text{SO}_2$  for sulfuric acid production. Equipment in the calcining operation include feeders for  $\text{MgSO}_3$  and coke, conveyor-elevators, an oil-fired fluid bed calciner, a combustion air blower, a waste heat boiler, a fabric dust filter and a recycle MgO storage silo. For treating the  $\text{MgSO}_3$  produced by removing 2.58 kg/s (10.3 ton/hr) of  $\text{SO}_2$ , the electric power requirements for the calcining operation are estimated at 380 kW. The heat rate for the fluid bed calciner is estimated at 17.4 MJ/s ( $59.6 \times 10^6$  Btu/hr). Based on use of No. 6 fuel oil requirements are 0.000420 m<sup>3</sup>/s (400 gal/hr). The waste heat boiler produces the equivalent of 4.23 MJ/s ( $14.4 \times 10^6$  Btu/hr) of steam. 3.38 MJ/s ( $11.5 \times 10^6$  Btu/hr) of this steam is sent to the slurry processing operation, while the remaining 0.85 MJ/s ( $2.9 \times 10^6$  Btu/hr) is credited to the flue gas reheater heat duty.

#### 1.1.9 Sulfuric Acid Production

The sulfuric acid production operation in the MgO FGD process is a conventional contact sulfuric acid plant. Based on a capacity of about 4.20 kg/s (400 ton/day) of 98 percent sulfuric acid, the electric power requirements for sulfuric acid production are estimated to be 1260 kW.

#### 1.1.10 Utilities and Services

The utilities and services required by the MgO FGD process are similar to those for the limestone process. For the base case design, the electric power requirements for utilities and services are estimated to be 140 kW.

#### 1.1.11 Base Case Summary

The electricity, steam, and fuel oil requirements for the base case MgO FGD process are summarized in Table C-2. As before a 500 MW power plant burning 3.5 percent sulfur coal without any SO<sub>2</sub> emission controls would require an energy input of 1.32 GJ/s ( $4.50 \times 10^9$  Btu/hr). Reducing the SO<sub>2</sub> emissions from this plant by 90 percent with a MgO FGD system would derate the power plant by 16 MW. This assumes that all electricity and steam requirements of the FGD system are obtained from the power plant. The uncontrolled plant net heat rate is 2640 J/kW-s (9,000 Btu/kW-hr). Since the net heat rate for the controlled plant is 2730 J/kW-s (9310 Btu/kW-hr), the energy penalty of the SO<sub>2</sub> control system is 90 J/kW-s (310 Btu/kW-hr). However, the base case MgO process also requires 0.000804 m<sup>3</sup>/s (765 gal/hr) of fuel oil. This is equivalent to 33.4 MJ/s ( $114 \times 10^6$  Btu/hr). Based on the controlled plant capacity of 484,000 kW, the additional energy penalty associated with the fuel oil requirements

TABLE C-2. SUMMARY OF BASE CASE ENERGY REQUIREMENTS - MgO FGD PROCESS

| Basis: 500 kW power plant burning 3.5% sulfur coal<br>90% SO <sub>2</sub> removal by MgO FGD process |                                         |                       |                                         |
|------------------------------------------------------------------------------------------------------|-----------------------------------------|-----------------------|-----------------------------------------|
| Area                                                                                                 | Oil, Steam and Electricity Requirements | x Conversion Factor = | Equivalent Energy Input to Boiler, MJ/s |
| Raw Material Handling and Preparation                                                                | 180 kW                                  | 2,640 J/kW-s          | 0.5                                     |
| Particulate/Chloride Removal                                                                         | 1,090 kW                                | 2,640 J/kW-s          | 2.9                                     |
| SO <sub>2</sub> Scrubbing                                                                            | 910 kW                                  | 2,640 J/kW-s          | 2.4                                     |
| Reheat                                                                                               | 7.44 kg steam/s                         | 1.99 MJ/kg steam*     | 14.8                                    |
| Fans                                                                                                 | 5,420 kW                                | 2,640 J/kW-s          | 14.3                                    |
| Slurry Processing                                                                                    | 380 kW                                  | 2,640 J/kW-s          | 1.0                                     |
| Cake Drying                                                                                          | 410 kW                                  | 2,640 J/kW-s          | 1.1                                     |
|                                                                                                      | 0.000384 m <sup>3</sup> oil/s           | **                    | **                                      |
| MgSO <sub>3</sub> Calcining                                                                          | 380 kW                                  | 2,640 J/kW-s          | 1.0                                     |
|                                                                                                      | 0.000420 m <sup>3</sup> oil/s           | **                    | **                                      |
| Sulfuric Acid Production                                                                             | 1,260 kW                                | 2,640 J/kW-s          | 3.3                                     |
| Utilities and Services                                                                               | 140 kW                                  | 2,640 J/kW-s          | 0.4                                     |
|                                                                                                      |                                         |                       | TOTAL = 41.7                            |
| Energy Input to Boiler                                                                               | 1,320 MJ/s                              |                       |                                         |
| Less SO <sub>2</sub> Control System                                                                  | 42 MJ/s                                 |                       |                                         |
| Net Available Energy                                                                                 | 1,278 MJ/s                              |                       |                                         |
| Uncontrolled Plant Net Heat Rate                                                                     | 2,640 J/kW-s                            |                       |                                         |
| Net Power Plant Capacity                                                                             | 484,000 kW                              |                       |                                         |
| Controlled Plant Net Heat Rate                                                                       | 2,730 kW                                |                       |                                         |

\* Based on an 88 percent boiler energy efficiency

\*\* Fuel oil requirements are not debited to the power plant

is 70 J/kW-s (240 Btu/kW-hr). Therefore, the overall SO<sub>2</sub> control system penalty is 160 J/kW-s (550 Btu/kW-hr).

A percentage breakdown of the energy requirements for the base case MgO FGD process are show below.

|                                       |     |
|---------------------------------------|-----|
| Raw material handling and preparation | <1% |
| Particulate/chloride removal          | 4%  |
| SO <sub>2</sub> scrubbing             | 3%  |
| Reheat                                | 20% |
| Fans                                  | 19% |
| Slurry processing                     | 1%  |
| Cake drying                           | 23% |
| MgSO <sub>3</sub> calcining           | 25% |
| Sulfuric acid production              | 4%  |
| Utilities and services                | <1% |

Particulate/chloride scrubbers, SO<sub>2</sub> scrubbers, reheaters, and fans account for almost 50 percent of the MgO system energy requirements. The energy requirements for these operations depend essentially only on flue gas flow rate. The SO<sub>2</sub> recovery operations - slurry processing, cake drying, MgSO<sub>3</sub> calcining and sulfuric acid production - also account for about one-half of the total system's energy requirements. Since the energy requirements for these operations are proportional to the amount of SO<sub>2</sub> removed, the energy requirements of the MgO system will exhibit a strong dependence on the amount of SO<sub>2</sub> removed.

#### 1.2 Base Case Extrapolations - MgO FGD Process

The electricity, fuel oil, and steam requirements for the three control cases which use the MgO FGD process can be extrapolated from the base case data. The electric power and

fuel oil requirements for the raw material handling and preparation, slurry processing, cake drying,  $\text{MgSO}_3$  calcining, and sulfuric acid production operations are proportional to the amount of  $\text{SO}_2$  removed. The electric power and steam requirements for particulate/chloride removal, the reheaters and utilities and services can be related to the amount of flue gas exiting the power plant air preheater. The following extrapolation factors were identified for these eight segments of the  $\text{MgO}$  FGD process.

|                                       |                                                         |
|---------------------------------------|---------------------------------------------------------|
| Raw material handling and preparation | - 68.0 kW/(kg $\text{SO}_2$ rem./s)                     |
| Particulate/chloride removal          | - 2.34 kW/(Nm <sup>3</sup> /s)                          |
| Reheat                                | - 28.1 kJ/Nm <sup>3</sup>                               |
| Slurry processing                     | - 146 kW/(kg $\text{SO}_2$ rem./s)                      |
| Cake drying                           | - 157 kW/(kg $\text{SO}_2$ rem./s)                      |
|                                       | - 0.000149 m <sup>3</sup> oil/(kg $\text{SO}_2$ rem./s) |
| $\text{MgSO}_3$ calcining             | - 145 kW/(kg $\text{SO}_2$ rem./s)                      |
|                                       | - 0.000162 m <sup>3</sup> oil/(kg $\text{SO}_2$ rem./s) |
| Sulfuric acid production-             | 473 kW/(kg $\text{SO}_2$ rem./s)                        |
| Utilities and services                | - 0.310 kW/(Nm <sup>3</sup> /s)                         |

The electric power requirements for the  $\text{SO}_2$  scrubbers and the I.D. fans are dependent on the  $\text{SO}_2$  concentration in the flue gas and the desired  $\text{SO}_2$  removal level. The energy requirements for these two operations in the three control cases which use the  $\text{MgO}$  FGD process are described below.

#### 1.2.1 $\text{SO}_2$ Scrubbing

The coal sulfur contents and desired  $\text{SO}_2$  control levels for the three control cases which utilize the  $\text{MgO}$  process are:

| <u>Coal Sulfur Content</u> | <u>SO<sub>2</sub> Control Level</u>      |
|----------------------------|------------------------------------------|
| 3.5%                       | 0.52 g SO <sub>2</sub> /MJ of heat input |
| 3.5% - base case -         | 90% SO <sub>2</sub> removal              |
| 7.0%                       | 90% SO <sub>2</sub> removal              |

For the first control case listed above, a venturi scrubber with a gas phase pressure of 0.75 kPa (3 in. H<sub>2</sub>O) (KO-174) and an L/G of 2.7 m<sup>3</sup>/1000 m<sup>3</sup> (20 gal/1000 acf) was selected. The electric power requirements for this scrubber used in a 500 MW power plant are estimated to be 910 kW. The second control case is the base case and as mentioned previously, the electric power requirements for SO<sub>2</sub> scrubbing are also established at 910 kW.

To remove 90 percent of the SO<sub>2</sub> produced by combustion of a 7.0 percent sulfur coal requires two contacting stages (SA-311). Therefore, for this case, a spray tower system integral to a venturi scrubber was selected as the SO<sub>2</sub> absorber. The spray system and venturi each operate at an L/G of 2.7 m<sup>3</sup>/1000 m<sup>3</sup> (20 gal/1000 acf) and have a total pressure drop of 1.6 kPa (6.5 in. H<sub>2</sub>O). For this SO<sub>2</sub> absorber used in a 500 MW power plant the electric power requirements for SO<sub>2</sub> scrubbing are estimated to be 1820 kW.

#### 1.2.2 Fans

The equation for calculating the power requirements for induced draft fans is given in Equation 1-5 in Appendix A. The pressure drops for use in this equation are shown below for the three control cases which use the MgO process.

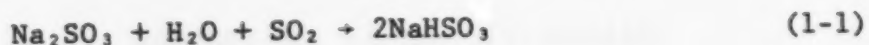
| <u>Coal</u> | <u>SO<sub>2</sub> Control Level</u>      | <u>ΔP kPa (in. H<sub>2</sub>O)</u> |        |
|-------------|------------------------------------------|------------------------------------|--------|
| 3.5% sulfur | 0.52 g SO <sub>2</sub> /MJ of heat input | 6.22                               | (25)   |
| 3.5% sulfur | 90% removal                              | 5.73                               | (23)   |
| 7.0% sulfur | 90% removal                              | 5.35                               | (21.5) |

## APPENDIX D

### WELLMAN-LORD/ALLIED FGD PROCESS

The Wellman-Lord/Allied (W-L/A) flue gas desulfurization process is an aqueous, regenerable SO<sub>2</sub> control process. A solution of sodium sulfite is used to absorb SO<sub>2</sub> from the flue gas. The scrubbing liquor is thermally regenerated to produce an SO<sub>2</sub> stream which is then converted into elemental sulfur. Figure D-1 is a simplified flow scheme of the W-L/A process selected for examination in this study.

Flue gas from the power plant air preheater enters a variable throat venturi scrubber. A fly ash slurry is injected into this venturi to remove particulates and chlorides. The flue gas next enters a three-plate valve-tray absorber. SO<sub>2</sub> is absorbed by a solution of sodium sulfite which is recirculated over each plate. The overall chemistry of the SO<sub>2</sub> absorption step can be represented by the following reaction:



The desulfurized flue gas is heated in an indirect steam reheater and compressed in an induced draft fan prior to entering the power plant stack for discharge to the atmosphere.

A portion of the recirculating SO<sub>2</sub> scrubbing solution is continuously removed and directed to the regeneration facilities. Here, the solution is cooled to crystallize any Na<sub>2</sub>SO<sub>4</sub> formed by oxidation of sulfite in the absorber. The Na<sub>2</sub>SO<sub>4</sub> is then separated, dried and recovered as a solid by-product. The liquid separated from the Na<sub>2</sub>SO<sub>4</sub> is sent to an evaporator/crystallizer wherein the reverse of Reaction 1-1 takes place. The SO<sub>2</sub> liberated serves as the feed to the Allied Chemical sulfur recovery process. A solution of soda ash and antioxidant

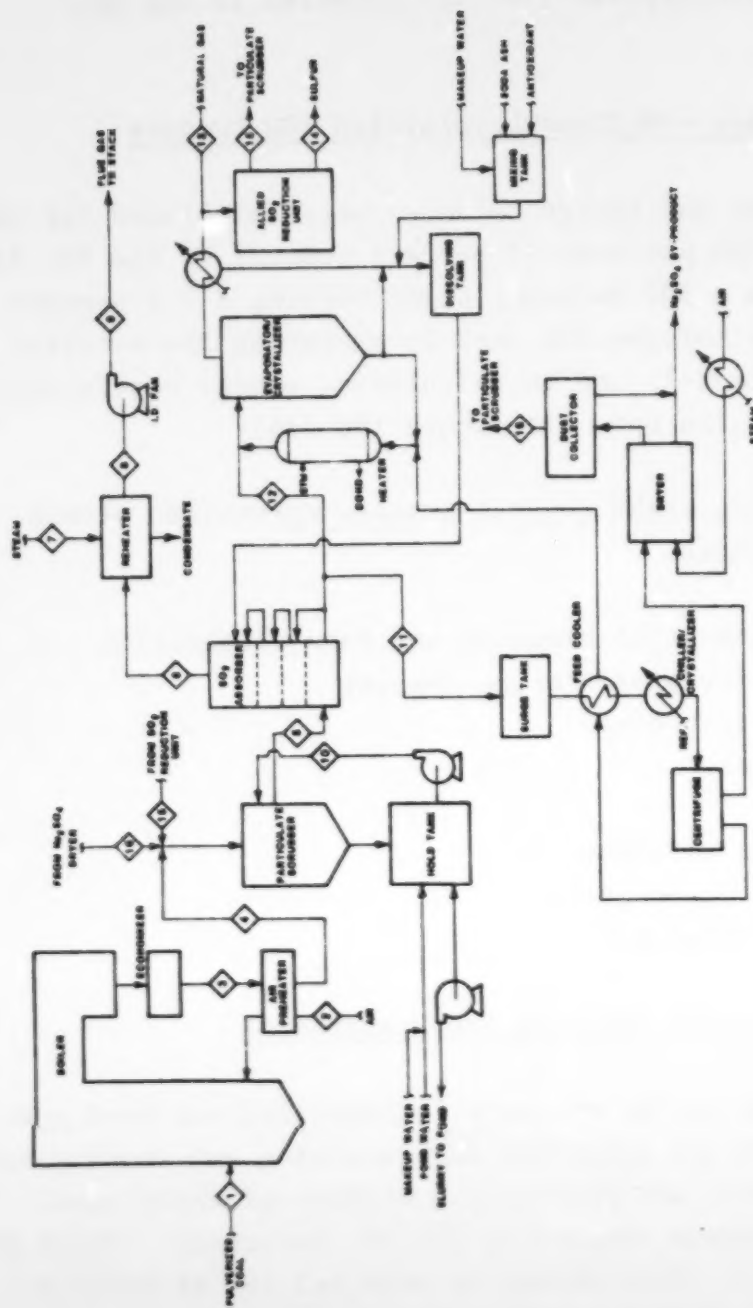


Figure D-1. Simplified flow scheme - Wellman-Lord/Allied FGD process

are prepared on-site, mixed with the  $\text{Na}_2\text{SO}_3$  crystals recovered from the evaporator/crystallizer and recycled to the  $\text{SO}_2$  absorbers.

### 1.1 Base Case - Wellman-Lord/Allied FGD Process

Material and energy balances were calculated for the base case W-L/A FGD process--90 percent removal of the  $\text{SO}_2$  from the flue gas from a 500 MW power plant burning a 3.5 percent sulfur coal. The information used in preparing the material balance (see Table D-1) and in calculating energy requirements was obtained from the open literature (MC-136).

There are eight general process operations within the W-L/A FGD process.

- Raw material handling and feed preparation
- Particulate/chloride removal
- $\text{SO}_2$  scrubbing
- Reheat
- Fans
- Purge treatment
- $\text{SO}_2$  regeneration
- $\text{SO}_2$  reduction

#### 1.1.1 Raw Material Handling and Preparation

Included in the raw material handling and feed preparation operation are equipment for receiving and storing soda ash and antioxidant, and producing a mixture of these chemicals for use as makeup reagent to the  $\text{SO}_2$  absorbers. Based on handling 0.344 kg/s (2650 lb/hr) of soda ash (99.8%  $\text{Na}_2\text{CO}_3$ ) and 5.71 g/s (45.3 lb/hr) of antioxidant, the electric power requirements are estimated to be 60 kW.

TABLE D-1. BASE CASE MATERIAL BALANCE--  
WELLMAN-LORD/ALLIED FGD PROCESS

| Stream No. | Stream Description                | Rate |                    |                   | Temperature, °K |
|------------|-----------------------------------|------|--------------------|-------------------|-----------------|
|            |                                   | kg/s | Nm <sup>3</sup> /s | m <sup>3</sup> /s |                 |
| 1          | Coal to Boiler                    | 47.3 |                    |                   |                 |
| 2          | Combustion Air to Boiler          | 570  | 430                |                   | 317             |
| 3          | Gas to Air Preheater              | 555  | 421                |                   | 647             |
| 4          | Gas to Particulate Scrubber       | 611  | 464                |                   | 428             |
| 5          | Gas to SO <sub>2</sub> Scrubber   | 664  | 522                |                   | 326             |
| 6          | Gas to Reheater                   | 662  | 518                |                   | 326             |
| 7          | Steam to Reheater                 | 7.57 |                    |                   | 517             |
| 8          | Gas to I.D. Fan                   | 662  | 518                |                   | 346             |
| 9          | Gas to Atmosphere                 | 662  | 518                |                   | 353             |
| 10         | Slurry to Particulate Scrubber    | 1231 |                    | 1.20              |                 |
| 11         | Liquor to Purge Treatment         | 11.7 |                    | 0.009             |                 |
| 12         | Liquor to Evaporator/Crystallizer | 19.7 |                    | 0.015             |                 |
| 13         | Natural Gas                       | 0.42 | 0.50               |                   | 367             |
| 14         | Elemental Sulfur                  | 1.18 |                    |                   |                 |
| 15         | Reduction Unit Tail Gas           | 2.98 | 2.43               |                   | 950             |
| 16         | Dryer Off Gas                     | 23.7 | 18.2               |                   | 383             |

### 1.1.2 Particulate/Chloride Removal

Included in the particulate/chloride removal operation are variable throat venturi scrubbers, effluent hold tanks and recirculating slurry, makeup water and slurry disposal pumps. The venturi scrubbers operate at a gas phase pressure drop of 2.1 kPa (8.5 in H<sub>2</sub>O) and an overall liquid to gas ratio (based on exit flue gas conditions) of 2 m<sup>3</sup>/1000<sup>3</sup>m (15 gal/1000 acf). For the base case design, the electric power requirements for the particulate scrubbing operation are estimated to be 1020 kW.

### 1.1.3 SO<sub>2</sub> Scrubbing

Included in the SO<sub>2</sub> scrubbing operation are three-plate valve tray absorbers and scrubbing solution recirculation pumps for each absorber plate. The absorbers operate at a pressure drop of 2.5 kPa (10 in. H<sub>2</sub>O) and, based on exit flue gas conditions, a liquid to gas ratio for each plate of 0.4 m<sup>3</sup>/1000 m<sup>3</sup> (3 gal/1000 acf). For the base case design, the electric power requirements for SO<sub>2</sub> scrubbing are estimated to be 320 kW.

### 1.1.4 Reheat

As for the other FGD processes, indirect steam reheaters are used to heat the scrubbed flue gas prior to discharge to the atmosphere. For the base case design which requires approximately 20°K (36°F) of reheat, the reheater heat duty is estimated at 13.3 MJ/s (45.3 x 10<sup>6</sup> Btu/hr). At an available steam heat content of 1.75 MJ/kg (755 Btu/lb), the steam rate to the reheater is 7.57 kg/s (60,000 lb/hr).

#### 1.1.5 Fans

To overcome the pressure drop of the flue gas as it passes through the W-L/A FGD process, induced draft fans are located downstream of the flue gas reheater. For the base case, design which has a pressure drop of 6.6 kPa (26 in. H<sub>2</sub>O), the electric power requirements for the fans are estimated to be 6200 kW.

#### 1.1.6 Purge Treatment

The purge treatment operation is designed to take a slipstream of the SO<sub>2</sub> absorber effluent and treat it for removal of sodium sulfate. The following equipment items are required:

- Ethylene glycol refrigeration system
- Chiller/crystallizer tank with agitator
- Feed cooler
- Centrifuge
- Conveyors
- Pumps
- Rotary dryer
- Fabric dust filter
- Induced draft fan

The purge stream is first cooled in the feed cooler and sent to the cooler/crystallizer. Na<sub>2</sub>SO<sub>4</sub> solids formed upon cooling are next separated in a centrifuge. The centrate is directed to the SO<sub>2</sub> regeneration operation while the solids are dried in a rotary dryer by air heated by an indirect stream/air heater. The dryer off-gases are treated for removal of entrained Na<sub>2</sub>SO<sub>4</sub> and then combined with the flue gas stream exiting the power plant preheater. The sodium sulfate by-product is sent to storage.

For the base case design in which 2.58 kg/s (10.3 ton/hr) of SO<sub>2</sub> are removed from the flue gas, the electric power requirements for purge treatment are estimated to be 930 kW. The heat duty for the steam/air heater is 4.51 MJ/s (15.4 x 10<sup>6</sup> Btu/hr). However, 2.66 MJ/s (9.07 x 10<sup>6</sup> Btu/hr) of this is assumed to be provided by steam produced in the SO<sub>2</sub> reduction operation. The heat duty that must be obtained from the power plant boiler is therefore 1.85 MJ/s (6.33 x 10<sup>6</sup> Btu/hr). At an available steam heat content of 1.75 MJ/kg (755 Btu/lb), the steam requirements are 1.06 kg/s (8380 lb/hr).

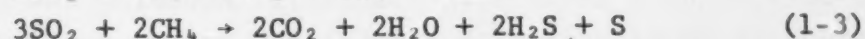
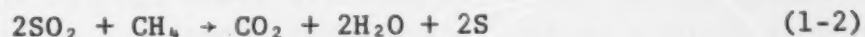
#### 1.1.7 SO<sub>2</sub> Regeneration

The SO<sub>2</sub> regeneration operation includes evaporator/crystallizers, pumps, condensers, condensate strippers, compressors and dissolving tanks. The evaporator/crystallizers produce an overhead stream of SO<sub>2</sub> and H<sub>2</sub>O and a concentrated slurry of Na<sub>2</sub>SO<sub>4</sub>. The H<sub>2</sub>O is removed from the overhead stream by cooling in water-cooled condensers. The condensate is mixed with the concentrated Na<sub>2</sub>SO<sub>4</sub> slurry, makeup soda ash and anti-oxidant and recycled to the SO<sub>2</sub> absorbers. The SO<sub>2</sub> is compressed and directed to the SO<sub>2</sub> reduction operation.

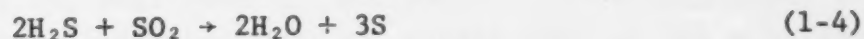
Based on removing 2.58 kg/s (10.3 ton/hr) of SO<sub>2</sub>, the electric power requirements for SO<sub>2</sub> regeneration are estimated at 1670 kW. The heat requirements are estimated at 79.1 MJ/s (271 x 10<sup>6</sup> Btu/hr). Based on steam available from the power plant boiler with a useful heat content of 1.75 MJ/kg (755 Btu/lb), the steam requirements are estimated at 45.3 kg/s (359,000 lb/hr).

#### 1.1.8 SO<sub>2</sub> Reduction

The SO<sub>2</sub> reduction operation includes a complete unit for the reduction of SO<sub>2</sub> to elemental sulfur. The reduction operation is based on a proprietary process developed by Allied Chemical. The heart of the process is the catalytic reduction of a major portion of the SO<sub>2</sub> to elemental sulfur and smaller amounts of H<sub>2</sub>S. The reductant is usually natural gas, although the use of reducing gases containing CO and H<sub>2</sub> such as are available from refineries or the gasification of coal have been tested. The two predominate reduction reactions are



The H<sub>2</sub>S produced from Reaction 1-3 and unreacted SO<sub>2</sub> are then converted to sulfur in a series of converter-condensers.



Since the three sulfur forming reactions are exothermic, a significant amount of useful energy is recovered in waste heat boilers.

Based on removing 2.58 kg/s (10.3 ton/hr) of SO<sub>2</sub>, the electric power and natural gas requirements of the SO<sub>2</sub> reduction operation are estimated to be 320 kW and 0.573 m<sup>3</sup>/s (72,800 scfh), respectively. This operation produces a steam heat credit of 3.46 MJ/s (11.8 x 10<sup>6</sup> Btu/hr) of which 0.804 MJ/s (2.73 x 10<sup>6</sup> Btu/hr) is used within the area for maintaining the by-product sulfur in a liquid state while in storage. The remaining 2.66 MJ/s (9.07 x 10<sup>6</sup> Btu/hr) are credited to the purge treatment operation.

### 1.1.9 Utilities and Services

The utilities and services required by the W-L/A FGD process are similar to those for other FGD processes. For the base case design, the electric power requirements for utilities and services are estimated to be 70 kW.

### 1.1.10 Base Case Summary

The electricity, steam and natural gas requirements for the base case W-L/A FGD process are summarized in Table D-2. As before, a 500 MW power plant burning a 3.5 percent sulfur coal without any SO<sub>2</sub> emission controls would require an energy input of 1.32 GJ/s ( $4.50 \times 10^9$  Btu/hr). Reducing the SO<sub>2</sub> emissions by 90 percent with a W-L/A FGD system would derate the power plant by 51 MW. This assumes that the electricity and steam requirements of the control system are obtained from the power plant. The uncontrolled plant net heat rate is 2640 J/kW-s (9000 Btu/kW-hr). Since the net heat rate for the controlled plant is 2940 J/kW-s (10,000 Btu/kW-hr), the energy penalty of the SO<sub>2</sub> control system is estimated at 300 J/kW-s (1080 Btu/kW-hr).

The natural gas requirements of the control system are 0.573 m<sup>3</sup>/s (72,800 scfh). This is equal to 22.4 MJ/s ( $76 \times 10^6$  Btu/hr) based on a natural gas energy content of 39.1 MJ m<sup>3</sup> (1050 Btu/scf). Since the controlled power plant capacity is 449,000 kW, the additional energy penalty associated with the natural gas requirements is 50 J/kW-s (170 Btu/kW-hr). Therefore, the overall SO<sub>2</sub> control system penalty is 350 J/kW-s (1190 Btu/kW-hr).

TABLE D-2. SUMMARY OF BASE CASE ENERGY REQUIREMENTS -  
WELLMAN-LORD/ALLIED FGD PROCESS

| Basis: 500 MW power plant burning a 3.5% sulfur coal<br>90% SO <sub>2</sub> removal via Wellman-Lord/Allied FGD Process |                                                       |    |                   |                                                 |
|-------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------|----|-------------------|-------------------------------------------------|
| Area                                                                                                                    | Natural Gas, Steam<br>and Electricity<br>Requirements | x  | Conversion Factor | =<br>Equivalent Energy<br>Input to Boiler, MJ/s |
| Raw Material Handling<br>and Preparation                                                                                | 60 kW                                                 |    | 2,640 J/kW-s      | 0.2                                             |
| Particulate/Chloride Removal                                                                                            | 1,020 kW                                              |    | 2,640 J/kW-s      | 2.7                                             |
| SO <sub>2</sub> Scrubbing                                                                                               | 320 kW                                                |    | 2,640 J/kW-s      | 0.8                                             |
| Reheat                                                                                                                  | 7.57 kg atm/s                                         |    | 1.99 MJ/kg atm*   | 15.1                                            |
| Fans                                                                                                                    | 6,200 kW                                              |    | 2,640 J/kW-s      | 16.4                                            |
| Purge Treatment                                                                                                         | 930 kW                                                |    | 2,640 J/kW-s      | 2.4                                             |
|                                                                                                                         | 1.06 kg atm/s                                         |    | 1.99 MJ/kg atm*   | 2.1                                             |
| SO <sub>2</sub> Regeneration                                                                                            | 1,670 kW                                              |    | 2,640 J/kW-s      | 4.4                                             |
|                                                                                                                         | 45.3 kg atm/s                                         |    | 1.99 MJ/kg atm*   | 90.1                                            |
| SO <sub>2</sub> Reduction                                                                                               | 320 kW                                                |    | 2,640 J/kW-s      | 0.8                                             |
|                                                                                                                         | 0.573 m <sup>3</sup> CH <sub>4</sub> /s               | ** |                   | **                                              |
| Utilities and Services                                                                                                  | 70 kW                                                 |    | 2,640 J/kW-s      | 0.2                                             |
|                                                                                                                         |                                                       |    |                   | TOTAL = 135.2                                   |
| Energy Input to Boiler                                                                                                  | 1,320 MJ/s                                            |    |                   |                                                 |
| Less SO <sub>2</sub> Control System                                                                                     | 135 MJ/s                                              |    |                   |                                                 |
| Net Available Energy                                                                                                    | 1,185 MJ/s                                            |    |                   |                                                 |
| Uncontrolled Plant Net Heat Rate                                                                                        | 2,640 J/kW-s                                          |    |                   |                                                 |
| Net Power Plant Capacity                                                                                                | 449,000 kW                                            |    |                   |                                                 |
| Controlled Plant Net Heat Rate                                                                                          | 2,940 J/kW-s                                          |    |                   |                                                 |

\*Based on an 88 percent boiler energy efficiency

\*\*Natural Gas requirements are not debited to the power plant

A percentage breakdown of the energy requirements for the W-L/A FGD process are shown below.

|                                       |       |
|---------------------------------------|-------|
| Raw material handling and preparation | - <1% |
| Particulate/chloride removal          | - 2%  |
| SO <sub>2</sub> scrubbing             | - 1%  |
| Reheat                                | - 10% |
| Fans                                  | - 10% |
| Purge treatment                       | - 3%  |
| SO <sub>2</sub> regeneration          | - 60% |
| SO <sub>2</sub> reduction             | - 15% |
| Utilities and Services                | - <1% |

The SO<sub>2</sub> recovery operations--purge treatment, SO<sub>2</sub> regeneration and SO<sub>2</sub> reduction-- account for about 80 percent of the total energy requirements for the W-L/A process. Since the energy requirements for these operations are proportional to the amount of SO<sub>2</sub> removed from the flue gas, the energy requirements of the whole process will also be a strong function of the amount of SO<sub>2</sub> removed.

#### 1.2 Base Case Extrapolations - W-L/A FGD Process

The electricity, natural gas and steam requirements for the three control cases which use the W-L/A FGD process can be extrapolated from the base case data. For the raw material handling and preparation, purge treatment, SO<sub>2</sub> regeneration and SO<sub>2</sub> reduction operations, the energy requirements are proportional to the amount of SO<sub>2</sub> removed. For the particulate/chloride scrubbers, reheaters and utilities and services, the electric power and steam requirements can be related to the flue gas flow rate exiting the power plant air preheater. The following extrapolation factors were identified for these seven segments of the W-L/A FGD process operations:

|                                       |                                                                                                           |
|---------------------------------------|-----------------------------------------------------------------------------------------------------------|
| Raw material handling and preparation | - 24.8 kW/(kg SO <sub>2</sub> rem./s)                                                                     |
| Particulate/chloride removal          | - 2.20 kJ/(Nm <sup>3</sup> /s)                                                                            |
| Reheat                                | - 28.6 kJ/(Nm <sup>3</sup> )                                                                              |
| Purge treatment                       | - 359 kW/(kg SO <sub>2</sub> rem./s)<br>717 kJ/(kg SO <sub>2</sub> rem./s)                                |
| SO <sub>2</sub> regeneration          | - 646 kW/(kg SO <sub>2</sub> rem./s)<br>306 MJ/(kg SO <sub>2</sub> rem./s)                                |
| SO <sub>2</sub> reduction             | - 114 kW/(kg SO <sub>2</sub> rem./s)<br>0.221 m <sup>3</sup> CH <sub>4</sub> /(kg SO <sub>2</sub> rem./s) |
| Utilities and services                | - 0.15 kW/(Nm <sup>3</sup> /s)                                                                            |

The L/G's and pressure drops for the SO<sub>2</sub> absorbers are dependent on the flue gas SO<sub>2</sub> concentrations and the desired SO<sub>2</sub> removal level. However, in a sodium based scrubbing system like the W-L/A process, SO<sub>2</sub> removal is only minimally dependent on L/G and pressure drop. Therefore, the base case L/G and system pressure drop were used for the three control cases which use the W-L/A process. The electric power requirements for the SO<sub>2</sub> scrubber and fans are then proportional to the flue gas flow rate and the following extrapolation factors were used:

|                           |                                |
|---------------------------|--------------------------------|
| SO <sub>2</sub> Scrubbing | - 0.69 kW/(Nm <sup>3</sup> /s) |
| Fans                      | - 13.4 kW/(Nm <sup>3</sup> /s) |

## APPENDIX E

### DOUBLE-ALKALI FGD PROCESS

The double-alkali (D-A) flue gas desulfurization process is essentially a hybrid process. The SO<sub>2</sub> absorption step utilizes a sodium based scrubbing liquor similar to that used in the Wellman-Lord/Allied process. Unlike the W-L/A process which recovers elemental sulfur, the D-A process is a nonregenerable process since the absorbed SO<sub>2</sub> is disposed of as a calcium based sludge. This portion of the D-A process is similar to the lime FGD process. Figure E-1 is a simplified flow scheme of the D-A FGD process selected for examination in this study.

Flue gas from the power plant air preheater first enters a variable throat venturi scrubber. A fly ash slurry is injected into this venturi to remove particulates and chlorides. The flue gas next enters a mobile bed absorber where the SO<sub>2</sub> is absorbed by a recirculating solution of sodium sulfite. The overall chemistry of the SO<sub>2</sub> absorption step can be represented by the following reaction.



The scrubbed flue gas is heated in an indirect steam reheater and compressed in an induced draft fan prior to entering the power plant stack for discharge to the atmosphere.

The SO<sub>2</sub> absorber effluent is reacted with lime slurry, causing calcium sulfite/sulfate to precipitate. A portion of the lime treated liquor is directed to a clarifier where soda ash is added to reduce the amount of dissolved calcium in the liquor and provide the necessary makeup of sodium ions. Calcium solids are removed from the clarifier, and sent to a lined pond for disposal, while the clarifier overflow is returned to the SO<sub>2</sub> absorbers.

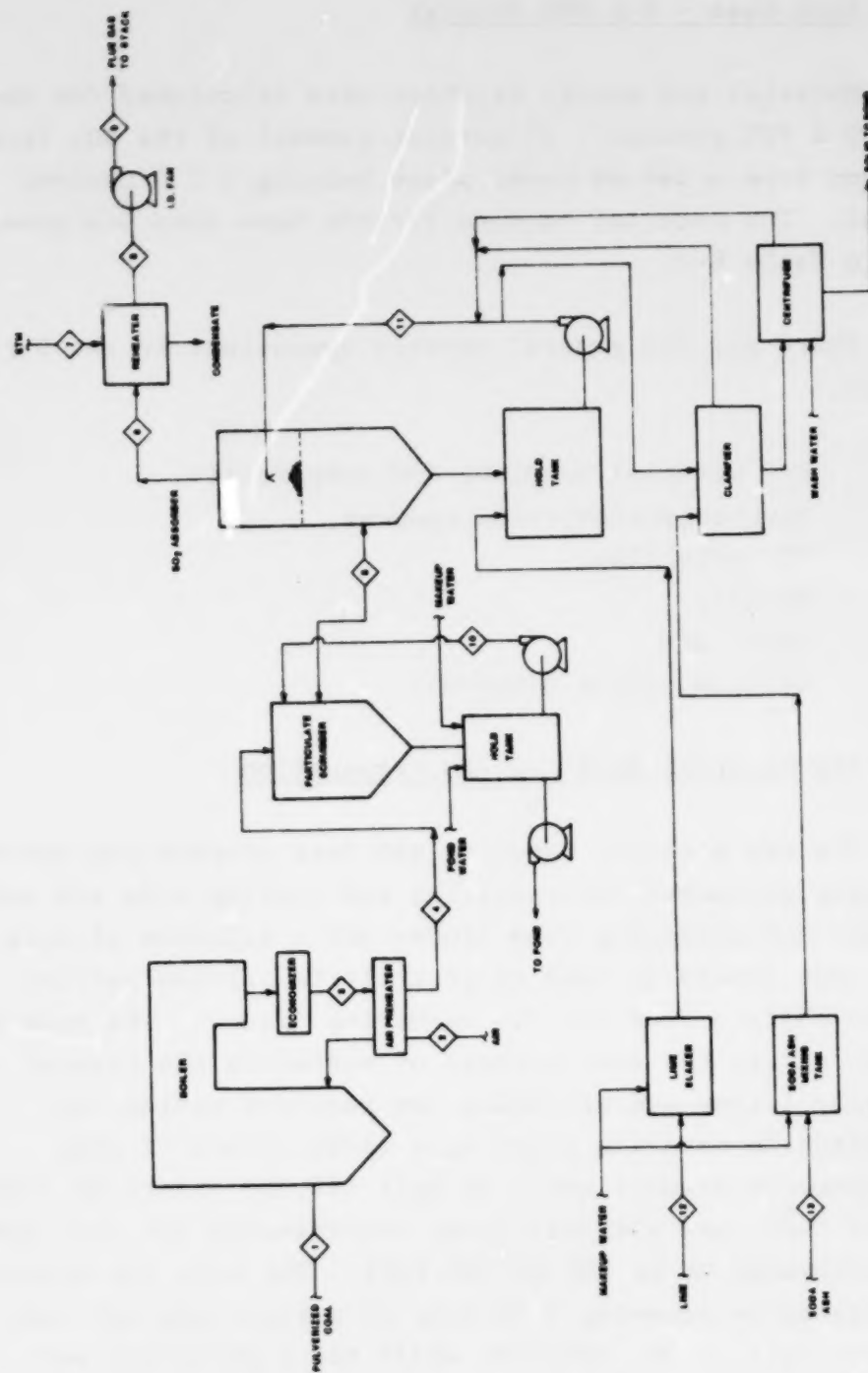


Figure E-1. Simplified flow scheme - double-alkali FGD process

## 1.1

### Base Case - D-A FGD Process

Material and energy balances were calculated for the base case D-A FGD process-- 90 percent removal of the  $\text{SO}_2$  from the flue gas from a 500 MW power plant burning a 3.5 percent sulfur coal. The material balance for the base case D-A process is given in Table E-1.

There are six general process operations in the D-A FGD process:

- Raw material handling and preparation,
- Particulate/chloride removal,
- $\text{SO}_2$  scrubbing,
- Reheat,
- Fans, and
- Calcium solids disposal.

#### 1.1.1

##### Raw Material Handling and Preparation

The raw material handling and feed preparation operation includes equipment for receiving and storing soda ash and pebble lime, and producing lime slurry and a solution of soda ash. The lime slurry is used to precipitate calcium sulfite and calcium sulfate from the  $\text{SO}_2$  scrubbing liquor. The solution of soda ash serves the dual purpose of softening the treated  $\text{SO}_2$  scrubbing liquor and providing the required sodium ion makeup. Based on handling 0.214 kg/s (1700 lb/hr) of soda ash (99.8 percent  $\text{Na}_2\text{CO}_3$ ) and 2.26 kg/s (17,900 lb/hr) of lime (95 percent  $\text{CaO}$ ), the electric power requirements for this operation are estimated to be 100 kW (MC-136). The soda ash requirements were calculated by assuming 0.05 mole of makeup soda ash were required per mole of  $\text{SO}_2$  removed, while the lime makeup was based on stoichiometric requirements (KA-227).

TABLE E-1. BASE CASE MATERIAL BALANCE--DOUBLE-ALKALI FGD PROCESS

| Stream No. | Stream Description                 | Rate |                    |                   | Temperature, °K |
|------------|------------------------------------|------|--------------------|-------------------|-----------------|
|            |                                    | kg/s | Nm <sup>3</sup> /s | m <sup>3</sup> /s |                 |
| 1          | Coal to Boiler                     | 47.3 |                    |                   |                 |
| 2          | Combustion Air to Boiler           | 570  | 430                |                   | 317             |
| 3          | Gas to Air Preheater               | 555  | 421                |                   | 647             |
| 4          | Gas to Particulate Scrubber        | 611  | 464                |                   | 428             |
| 5          | Gas to SO <sub>2</sub> Absorber    | 635  | 500                |                   | 326             |
| 6          | Gas to Reheater                    | 637  | 518                |                   | 325             |
| 7          | Steam to Reheater                  | 8.88 |                    |                   | 517             |
| 8          | Gas to I.D. Fan                    | 637  | 518                |                   | 346             |
| 9          | Gas to Atmosphere                  | 637  | 518                |                   | 353             |
| 10         | Slurry to Particulate Scrubbing    | 1231 |                    | 1.2               |                 |
| 11         | Slurry to SO <sub>2</sub> Absorber | 1568 |                    | 1.2               |                 |
| 12         | Makeup Lime                        | 2.9  |                    |                   |                 |
| 13         | Makeup Soda Ash                    | 0.21 |                    |                   |                 |

### 1.1.2 Particulate/Chloride Removal

The venturi scrubbers used for control of particulates and chlorides in the D-A FGD process are essentially identical to the venturi scrubbers used in the MgO process. Based on an L/G of  $2 \text{ m}^3/1000 \text{ m}^3$  (15 gal/1000 acf), the electric power requirements for particulate scrubbing are estimated to be 1090 kW (MC-136).

### 1.1.3 SO<sub>2</sub> Scrubbing

Included in the SO<sub>2</sub> scrubbing operation are mobile bed absorbers, scrubbing liquor hold tanks and liquor recirculation pumps. The SO<sub>2</sub> absorbers operate at an L/G of  $2 \text{ m}^3/1000 \text{ m}^3$  (15 gal/1000 scf) and a pressure drop of 2.1 kPa (8.5 in. H<sub>2</sub>O). For the base case design, the electric power requirements for SO<sub>2</sub> scrubbing are estimated to be 860 kW (MC-136).

### 1.1.4 Reheat

As for the other FGD processes, indirect steam reheaters are used to heat the scrubbed flue gas prior to discharge to the atmosphere. For the base case design which requires approximately 21°K (38°F) of reheat, the reheater heat duty is estimated at 15.6 MJ/s ( $53.2 \times 10^6$  Btu/hr). At an available steam heat content of 1.75 MJ/kg (755 Btu/lb), the steam rate to the reheater is estimated at 8.88 kg/s (70,400 lb/hr) (MC-136).

### 1.1.5 Fans

To overcome the pressure drop of the flue gas as it passes through the D-A FGD process, induced draft fans are located downstream of the flue gas reheater. For the base case design which has a system pressure drop of 5.7 kPa (23 in. H<sub>2</sub>O), the electric power requirements for the fans are estimated to be 5510 kW (MC-136).

#### 1.1.6 Calcium Solids Disposal

SO<sub>2</sub> absorber effluent which has been treated with lime slurry is sent to clarifiers for softening with a solution of soda ash. The CaCO<sub>3</sub> solids formed here and the CaSO<sub>3</sub> and CaSO<sub>4</sub> solids formed by the lime treatment are removed from the bottom of the clarifier and directed to centrifuges. The solids from the centrifuges are washed with water and then combined with the effluent from the particulate scrubbers for disposal in a lined settling pond. Pond water is recycled to the raw material handling and feed preparation operation. The clarifier overflow and centrifuge wash are recycled to the SO<sub>2</sub> absorbers. Based on handling the solids formed by removing 2.58 kg/s (10.3 ton/hr) of SO<sub>2</sub>, the electric power requirements for calcium solids disposal are estimated at 250 kW (MC-136).

#### 1.1.7 Utilities and Services

The utilities and services required by the double-alkali FGD process are similar to those for the limestone process. For the base case design, the electric power requirements for utilities and services are estimated to be 60 kW (MC-136).

#### 1.1.8 Base Case Summary

The electricity and steam requirements for the base case D-A FGD process are summarized in Table E-2. As before, a 500 MW power plant burning 3.5 percent sulfur coal without any SO<sub>2</sub> emission controls would require an energy input of 1.32 GJ/s ( $4.50 \times 10^9$  Btu/hr). Reducing the SO<sub>2</sub> emissions from this plant by 90 percent with a D-A FGD system would derate the power plant by 15 MW. This assumes that all energy needs of the FGD system are obtained from the power plant. The

TABLE E-2. SUMMARY OF BASE CASE ENERGY REQUIREMENTS - DOUBLE-ALKALI FGD PROCESS

| Basis: 500 MW power plant burning a 3.5% sulfur coal<br>90% SO <sub>2</sub> removal via Double-Alkali FGD process |                                       |   |                   |                                                 |
|-------------------------------------------------------------------------------------------------------------------|---------------------------------------|---|-------------------|-------------------------------------------------|
| Area                                                                                                              | Electricity and<br>Steam Requirements | x | Conversion Factor | =<br>Equivalent Energy<br>Input to Boiler, MJ/s |
| Raw Material Handling<br>and Preparation                                                                          | 100 kW                                |   | 2,640 J/kW-s      | 0.3                                             |
| Particulate/Chloride Removal                                                                                      | 1,090 kW                              |   | 2,640 J/kW-s      | 2.9                                             |
| SO <sub>2</sub> Scrubbing                                                                                         | 860 kW                                |   | 2,640 J/kW-s      | 2.3                                             |
| Reheat                                                                                                            | 8.88 kg stm/s                         |   | 1.99 MJ/kg stm*   | 17.7                                            |
| Fans                                                                                                              | 5,510 kW                              |   | 2,640 J/kW-s      | 14.5                                            |
| Calcium Solids Disposal                                                                                           | 250 kW                                |   | 2,640 J/kW-s      | 0.7                                             |
| Utilities and Services                                                                                            | 60 kW                                 |   | 2,640 J/kW-s      | 0.2                                             |
|                                                                                                                   |                                       |   |                   | TOTAL = 38.6                                    |
| Energy Input to Boiler                                                                                            | 1,320 MJ/s                            |   |                   |                                                 |
| Less SO <sub>2</sub> Control System                                                                               | 39 MJ/s                               |   |                   |                                                 |
| Net Available Energy                                                                                              | 1,281 MJ/s                            |   |                   |                                                 |
| Uncontrolled Plant Net Heat Rate                                                                                  | 2,640 J/kW-s                          |   |                   |                                                 |
| Net Power Plant Capacity                                                                                          | 485,000 kW                            |   |                   |                                                 |
| Controlled Plant Net Heat Rate                                                                                    | 2,720 J/kW-s                          |   |                   |                                                 |

\*Based on an 88 percent boiler energy efficiency

uncontrolled plant net heat rate is 2640 J/kW-s (9000 Btu/kW-hr). Since the net heat rate for the controlled plant is 2720 J/kW-s (9280 Btu/kW-hr), the energy penalty of the SO<sub>2</sub> control system is 80 J/kW-s (280 Btu/kW-hr).

A percentage breakdown of the energy requirements for the base case D-A FGD process are shown below.

|                                       |       |
|---------------------------------------|-------|
| Raw material handling and preparation | - <1% |
| Particulate/chloride removal          | - 7%  |
| SO <sub>2</sub> scrubbing             | - 6%  |
| Reheat                                | - 46% |
| Fans                                  | - 38% |
| Calcium solids disposal               | - 2%  |
| Utilities and services                | - <1% |

Particulate/chloride scrubbers, reheaters, and fans account for over 90 percent of the D-A system energy requirements. The energy requirements for these areas depend essentially only on the flue gas flow rate. Therefore, the energy requirements for the D-A process will depend very little on inlet flue gas SO<sub>2</sub> concentration or SO<sub>2</sub> removal level.

## 1.2 Base Case Extrapolations

The electricity and steam requirements for the three control cases which use the D-A FGD process can be extrapolated from the base case data. The electric power requirements for the raw material handling and preparation, and calcium solids disposal operations are proportional to the amount of SO<sub>2</sub> removed. For the particulate/chloride scrubbers, reheaters, and utilities and services, the electric power and steam requirements can be related to the flue gas flow rate exiting the power plant air preheater.

The following extrapolation factors were identified for these five segments of the D-A FGD process:

|                                       |                                       |
|---------------------------------------|---------------------------------------|
| Raw material handling and preparation | - 38.8 kW/(kg SO <sub>2</sub> rem./s) |
| Particulate/chloride removal          | - 2.34 kW/(Nm <sup>3</sup> /s)        |
| Reheat                                | - 33.5 kJ/Nm <sup>3</sup>             |
| Calcium solids disposal               | - 95.6 kW/(kg SO <sub>2</sub> rem./s) |
| Utilities and services                | - 0.14 kW/(Nm <sup>3</sup> /s)        |

While the L/G and pressure drop required by the SO<sub>2</sub> absorbers are dependent on the flue gas SO<sub>2</sub> concentration and the desired SO<sub>2</sub> removal level, this dependence in a sodium-based scrubbing system like the double-alkali process is minimal. Therefore, the base case L/G and system pressure drop were used for the three control cases which use the D-A process. The electric power requirements for the SO<sub>2</sub> scrubbing and fans areas are then proportional to the flue gas flow rate and the following extrapolation factors were used:

|                           |                                |
|---------------------------|--------------------------------|
| SO <sub>2</sub> scrubbing | - 1.84 kW/(Nm <sup>3</sup> /s) |
| Fans                      | - 11.9 kW/(Nm <sup>3</sup> /s) |

APPENDIX F  
PHYSICAL COAL CLEANING

Physical coal cleaning processes remove impurities from coal via a mechanical separation process. In most cleaning operations, this separation of impurities is based on a gravity difference between coal (which is relatively light) and contaminants such as pyrite ( $\text{FeS}_2$ ), ash, and rock (which are heavier) (WE-003). Historically, ash and rock removal were the primary objectives of coal cleaning. However, the need for reducing sulfur dioxide emissions has recently focused more attention on the sulfur removal aspects of physical coal cleaning.

Sulfur occurs in a coal seam in three basic forms: pyritic, organic, and sulfate. In any given coal the amount of sulfate sulfur is negligible. Physical coal cleaning is restricted to removal of the pyritic sulfur from coal. This is due to the fact that the organic sulfur in coal is chemically bound and requires a chemical extraction process for removal.

The effectiveness of a physical coal cleaning process in removing sulfur from coal is both coal and process specific (DE-064). Data related to the ability to physically clean the 3.5 and 7.0 percent sulfur coals examined in this study were not available. Therefore, it was necessary to select a generalized coal cleaning plant. Figure F-1 is a simplified flow scheme of a physical coal cleaning facility depicting common process areas (LO-071, CO-380). The coal cleaning plant represented by this flow scheme was selected for this study.

The following four process areas are present in the coal cleaning facilities shown in Figure F-1. Listed under each area are various operations which may be utilized in an individual cleaning process.

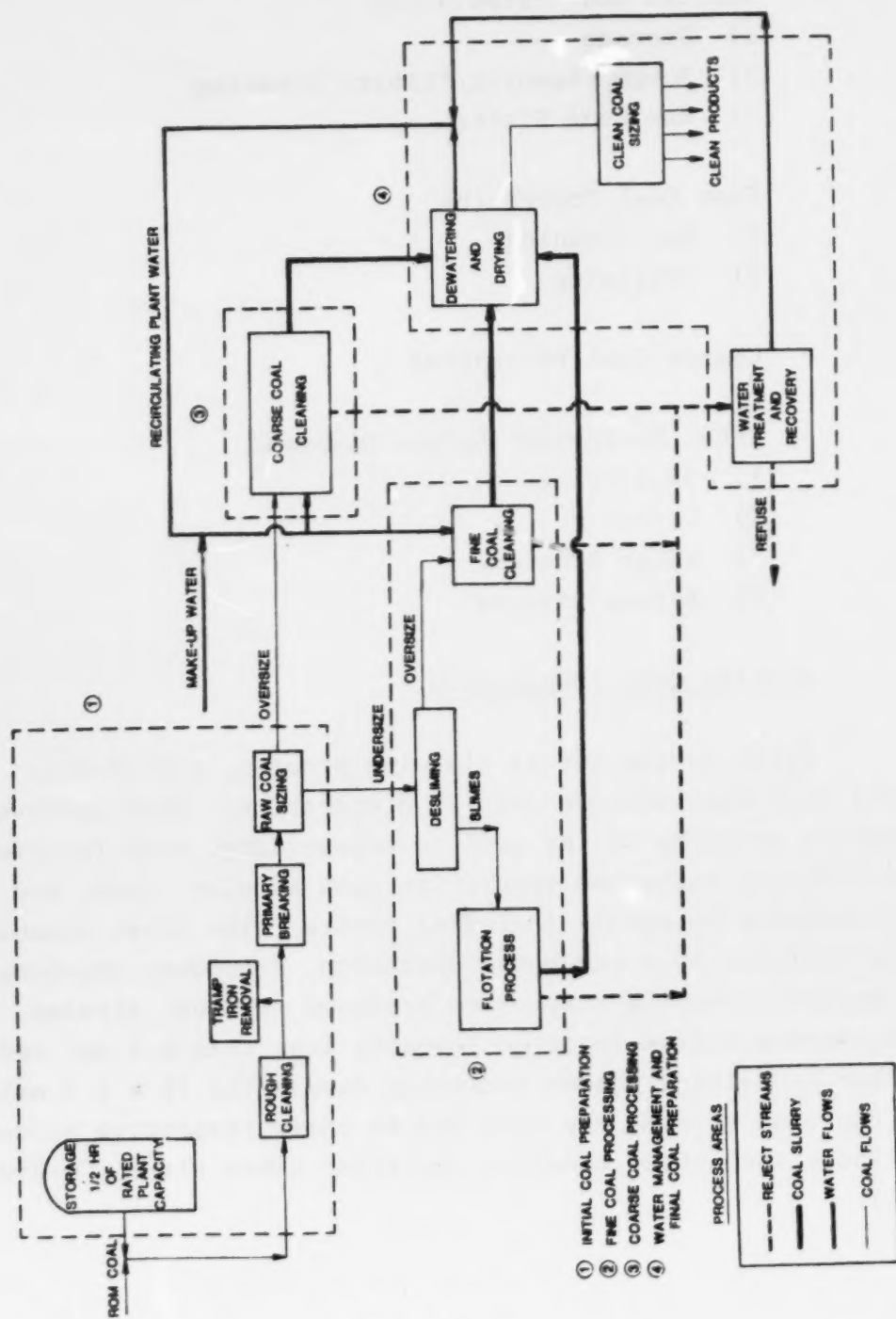


Figure F-1. Simplified flow scheme--Physical Coal Cleaning Process.

- Initial Coal Preparation
  - 1) Storage
  - 2) Rough Cleaning/Primary Breaking
  - 3) Raw Coal Sizing
- Fine Coal Processing
  - 1) Wet Cleaning
  - 2) Desliming
- Coarse Coal Processing
- Water Management/Refuse Disposal
  - 1) Dewatering
  - 2) Drying
  - 3) Water Recovery
  - 4) Refuse Disposal

#### 1.1 Initial Coal Preparation

Prior to the actual cleaning process, run-of-mine (R.O.M.) coal must undergo initial preparation. This involves preliminary crushing of the coal to remove large rock fractions and to liberate entrained impurities such as clay, rock, and other inorganic materials including pyrite. The first crushing step is followed by a screening operation, secondary crushing, and a second screening step which produces two coal streams; one containing a fine fraction (usually less than 6.5 mm) and the other containing coarse particles (nominally 76 x 6.5 mm). These two coal streams are then fed to their respective process areas where the actual cleaning operation takes place (CO-380, LO-071).

## 1.2 Fine Coal Processing

The process feed stream of less than 6.5 mm coal is slurried with water as it enters the fine coal processing area. This slurry is then subjected to a desliming operation which removes a suspension containing approximately 50 percent of minus 200 mesh material (FI-102).

After desliming, the oversize coal fraction (greater than 28 mesh) is pumped to the fine coal cleaning process. Here, fine coal particles undergo gravity separation in one of several wet cleaning devices. This removes a percentage of the ash and pyritic sulfur to produce a clean coal product. The product stream from this operation is then fed to the drying area of the plant and refuse material is further processed in the water treatment section.

The slimes removed from the fine coal are fed to a froth flotation process. Upon entering the flotation process area, the slime suspension is treated with a frothing agent which selectively floats coal particles in the flotation machines while allowing pyrite and ash impurities to settle. The float product is then sent to the dewatering area while reject material is processed in the water treatment and recovery area.

## 1.3 Coarse Coal Processing

Feed to the coarse coal processing area of the plant consists of oversize material (76 x 6.5 mm particles) from the initial preparation area. This feed stream is slurried with water prior to cleaning in one of the many types of process equipment currently employed in coarse coal cleaning. Here, impurities are separated from the coal using differences in

coal and reject densities. It is also common practice to remove a middling fraction from the separation operation and further process it by means of recycle or by feed to another cleaning process. These cleaning operations result in two streams being removed from the coarse coal processing area: a product and reject stream. After the coarse cleaning operation, the product stream is pumped to the dewatering and drying area of the plant while the reject stream is processed in the water treatment and recovery area.

#### 1.4 Water Management/Refuse Disposal

Dewatering and drying equipment handle the product flows from both the fine and coarse coal preparation areas. Typically, cleaning plants employ mechanical dewatering operations to separate coal slurries into a low-moisture solid and a clarified supernatant. The solid coal sludge produced in the dewatering step can then be mechanically or thermally dried to further reduce the moisture while the supernatant from the dewatering process is returned to the plant's water circulation system.

The water treatment and recovery section of a cleaning plant processes refuse slurries containing both coarse material and reject slimes. Here, the refuse slurry is dewatered in thickeners and settling ponds. The supernatant from this operation is returned for reuse in the plant while the refuse is buried and revegetated to prevent spontaneous ignition.

The coal product from the dewatering and drying area of the plant can be further processed. This may involve crushing and screening operations to separate the product into various product sizes.

Physical Coal Cleaning Design Premises

As mentioned previously, the design of a physical coal cleaning plant is dependent on the properties of the coal to be cleaned. However, physical coal cleaning data were not available for the 3.5 and 7.0 percent sulfur coals considered in this study. In order to develop energy requirements for the coal cleaning plant, several assumptions had to be made. These assumptions are discussed in the following paragraphs.

To achieve sulfur removal levels of about 40 percent would require a fairly sophisticated cleaning plant. In general, as a cleaning plant becomes more sophisticated or complex, its energy recovery efficiency also increases. Therefore, a 95 percent energy recovery--95 percent of the input coal energy was recovered in the clean coal product--was used (RO-325).

Other assumptions used in calculating the energy requirements of a coal cleaning plant were (CH-307):

- (1) The electric power requirements for a 278 kg/s (500 ton/hr) cleaning plant are 2980 kW.
- (2) The heat duty of a thermal dryer is 534 kJ/kg (230 Btu/lb) of coal dried.
- (3) One half of the clean coal product (the coal fines) is thermally dried.
- (4) Heat for the thermal dryers is supplied by burning a portion of the clean coal product.

- (5) 50% of the ash content of the coal is removed.
- (6) The average heating value of the clean coal is 29.2 MJ/kg (12,500 Btu/lb).

Based on these assumptions, the estimated compositions of the physically cleaned 3.5 and 7.0 percent sulfur coals are as shown in Table F-1. The energy requirements and throughput for physical coal cleaning plants supplying coal to 500 MW and 25 MW power plants are summarized in Table F-2.

When assessing the energy penalty of the coal cleaning process, the electricity requirements are assumed to be obtained from the power plant and are reflected in the power plant's net heat rate. The penalty associated with the coal lost and used in the cleaning process are debited to the control system by requiring an increase in the coal feed rate to the cleaning plant.

TABLE F-1. COMPOSITIONS OF PHYSICALLY CLEANED COALS

|                         | Physically cleaned<br>3.5% sulfur coal | Physically cleaned<br>7.0% sulfur coal |
|-------------------------|----------------------------------------|----------------------------------------|
| MAF Coal, wt. %         | 87.1                                   | 87.1                                   |
| Ash, wt. %              | 6.6                                    | 6.6                                    |
| H <sub>2</sub> O, wt. % | 6.3                                    | 6.3                                    |
| Sulfur, wt. %           | 2.2                                    | 4.4                                    |
| Heating Value, MJ/kg    | 29.2                                   | 29.2                                   |

TABLE F-2. ENERGY REQUIREMENTS FOR PHYSICAL COAL CLEANING

| Power Plant Capacity                        | 25 MW                           | 500 MW                         |
|---------------------------------------------|---------------------------------|--------------------------------|
| Energy Input to Boiler, MJ/s (Btu/hr)       | 68.1 (232 x 10 <sup>6</sup> )   | 1320 (4.50 x 10 <sup>9</sup> ) |
| Coal Rate to Boiler, kg/s (tons/hr)         | 2.34 (9.30)                     | 45.4 (180)                     |
| Heat Duty of Thermal Dryer, MJ/s (Btu/hr)   | 0.633 (2.16 x 10 <sup>6</sup> ) | 12.2 (41.8 x 10 <sup>6</sup> ) |
| Total Cleaned Coal Produced, MJ/s (Btu/hr)  | 68.8 (235 x 10 <sup>6</sup> )   | 1330 (4.54 x 10 <sup>9</sup> ) |
| Total Cleaned Coal Produced, kg/s (tons/hr) | 2.37 (9.39)                     | 45.8 (182)                     |
| Coal Lost with Ash, MJ/s (Btu/hr)           | 3.62 (12.4 x 10 <sup>6</sup> )  | 70 (0.239 x 10 <sup>9</sup> )  |
| Total Coal Consumed or Lost, MJ/s (Btu/hr)  | 4.25 (14.5 x 10 <sup>6</sup> )  | 82.3 (281 x 10 <sup>6</sup> )  |
| Electric Power Requirements, kW             | 60                              | 1080                           |

The following information was obtained from the records of the Department of the Interior, Bureau of Land Management, regarding the land owned by the United States in the State of California. The information was obtained from the records of the Department of the Interior, Bureau of Land Management, regarding the land owned by the United States in the State of California. The information was obtained from the records of the Department of the Interior, Bureau of Land Management, regarding the land owned by the United States in the State of California.

## APPENDIX G

### COAL TRANSPORTATION

The following information was obtained from the records of the Department of the Interior, Bureau of Land Management, regarding the land owned by the United States in the State of California. The information was obtained from the records of the Department of the Interior, Bureau of Land Management, regarding the land owned by the United States in the State of California. The information was obtained from the records of the Department of the Interior, Bureau of Land Management, regarding the land owned by the United States in the State of California.

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COAL TRANSPORTATION

Unit trains are the major method used to transport coal over long distances. Unit trains are railroad systems dedicated solely to the movement of coal from a coal mine or coal preparation plant to an end user. For this study, unit trains are used to transport western coal from a mine in the Four Corners area of New Mexico to a power plant in Ohio. The total one-way train distance between these two points is assumed to be 2,100 km (1,300 miles). The following assumptions were used in calculating the energy requirements of a unit train:

- 1) Each unit train consists of 100 coal cars with a coal capacity of 91,000 kg (100 ton) (WH-101).
- 2) Each unit train uses 5 locomotives rated at 2,700 kW (3,600 HP) with the following diesel fuel oil consumption (WH-101, RA-215):
  - At full power: 0.00022 m<sup>3</sup>/s (200 gal/hr) per locomotive
  - At reduced power: 0.000029 m<sup>3</sup>/s (28 gal/hr) per locomotive
- 3) Four hours each are required for loading and unloading while the train moves at reduced power (BU-116, RA-215).
- 4) One hour is required for passing a large city and for undergoing each federal inspection, while the train moves at reduced power (BU-116, RA-215).

- 5) One large city every 180 km (110 miles) and one federal inspection every 800 km (500 miles).
- 6) Average train speed in open country is 48 km/hr (30 mph) when loaded and 96 km/hr (60 mph) when empty (SO-138).
- 7) One percent of the total train load is lost as coal dust blow-off which occurs primarily during loading and unloading (CO-129).
- 8) Diesel fuel oil has a heating value of 38.4 GJ/m<sup>3</sup> (138,000 Btu/gal).

Table G-1 shows how these assumptions were used to calculate the energy required to transport low sulfur western coal to a Midwest power plant. The energy penalties for the control systems which examine transporting low sulfur western coal are given in Table G-2.

TABLE G-1. CALCULATION OF ENERGY REQUIREMENTS  
FOR TRANSPORTING WESTERN COAL

Basis: One round trip unit train delivery

# of hours at reduced power:

|                                   |            |
|-----------------------------------|------------|
| Passing large cities (24)         | - 24       |
| Undergoing federal inspection (4) | - 4        |
| Loading                           | - 4        |
| Unloading                         | - <u>4</u> |
| Total                             | - 36 hrs.  |

# of hours at full power:

|                         |             |
|-------------------------|-------------|
| En route to power plant | - 43        |
| Return to mine          | - <u>22</u> |
| Total                   | - <u>65</u> |
| TOTAL duration of trip  | - 101 hrs.  |

Fuel Consumption:

|                 |                   |
|-----------------|-------------------|
| @ reduced power | - 734 GJ          |
| @ full power    | - <u>9,460 GJ</u> |
| Total           | - 10,190 GJ       |
| Average         | - 28.0 MJ/s       |

|                       |             |
|-----------------------|-------------|
| Windage Losses, Total | - 90,800 kg |
| Average               | - 0.25 kg/s |

|                                                   |              |            |
|---------------------------------------------------|--------------|------------|
| Coal Transported, MJ/kg coal                      | <u>20.9</u>  | 25.6       |
| Average Fuel Consumption, MJ/s                    | - 28.0       | 28.0       |
| Average Windage Losses, MJ/s                      | - <u>5.2</u> | <u>6.4</u> |
| Total average Energy Consumed or Lost, MJ/s       | - 33.2       | 34.4       |
| Total average Energy Consumed or Lost, MJ/kg coal | - 1.33       | 1.38       |

TABLE G-2. ENERGY PENALTY -- COAL TRANSPORTATION

| Coal                    | Power Plant Size<br>MW | Coal Rate<br>kg/s | Transportation<br>Energy Penalty |        |
|-------------------------|------------------------|-------------------|----------------------------------|--------|
|                         |                        |                   | MJ/s                             | J/kW-s |
| 0.4% Sulfur; 20.9 MJ/kg | 25                     | 3.26              | 4.3                              | 170    |
| 0.4% Sulfur; 20.9 MJ/kg | 500                    | 63.0              | 84                               | 170    |
| 0.6% Sulfur; 25.6 MJ/kg | 25                     | 2.66              | 3.7                              | 150    |
| 0.6% Sulfur; 25.6 MJ/kg | 500                    | 51.6              | 71                               | 140    |